APPENDIX 8.1A

Detailed Emissions Calculations

Table 8.1A-1
Central Valley Energy Center
Emissions and Operating Parameters for Gas Turbines/HRSGs

	Case 1	Case 2	Case 3	Case 4	Case 5
	100 deg Full Load w/ DB&PA	100 deg 70% Load	61 deg Full Load	32 deg 100% Load	32 deg 70% Load
Ambient Temp, F	100	100	61	32	32
GT Load	100	70	100	100	70
GT heat input, MMBtu/hr (HHV)	1888.0	1268.0	1866.0	1968.5	1471
DB heat input, MMBtu/hr (HHV)	735.0	0.0	0.0	0.0	0.0
Stack flow, lb/hr	3,644,882	2,900,968	3,689,788	3,857,119	3,192,331
Stack flow, acfm	1,012,416	791,788	1,037,152	1,072,015	890,000
Stack temp, F	168	174	193	187	190
Stack exhaust, vol %					
O2 (dry)	9.80	14.65	13.62	13.60	14.34
CO2 (dry)	6.37	3.61	4.19	4.21	3.79
H2O	16.73	8.1	8.5	8.0	7.3
Emissions					
NOx, ppmvd @ 15% O2	2.5	2.5	2.5	2.5	2.5
NOx, lb/hr	23.77	11.49	16.91	17.83	13.33
NOx, lb/MMBtu	0.0091	0.0091	0.0091	0.0091	0.0091
SO2, ppmvd @ 15% O2	0.139	0.139	0.139	0.139	0.139
SO2, lb/hr	1.837	0.888	1.31	1.38	1.04
SO2, lb/MMBtu	0.0007	0.0007	0.0007	0.0007	0.0007
CO, ppmvd @ 15% O2	6.00	6.00	6.00	6.00	6.00
CO, lb/hr	34.73	16.79	24.70	26.06	19.47
CO, lb/MMBtu	0.0132	0.0132	0.0132	0.0132	0.0132
VOC, ppmvd @ 15% O2	2.0	1.4	1.4	1.4	1.4
VOC, lb/hr	6.63	2.24	3.30	3.48	2.60
VOC, lb/MMBtu	0.0025	0.0018	0.0018	0.0018	0.0018
PM10, lb/hr	16.4	11.0	11.0	11.0	11.0
PM10, lb/MMBtu	0.0062	0.0087	0.0059	0.0056	0.0075
PM10, gr/dscf	0.00274	0.00215	0.0017	0.00162	0.00194
NH3, ppmvd@15% O2	10.0	10.0	10.0	10.0	10.0
NH3, lb/hr	35.19	17.01	25.03	26.41	19.73

Table 8.1A-2
Auxiliary Boiler Characteristics
Central Valley Energy Center

Boiler Emission Characteristics	
Auxiliary Boiler, MMBtu/hr (HHV)	161
Boiler Rating, lb/hr	125,000
NOx, ppmvd @ 3% O2	9.0
Ammonia Slip, ppmvd @ 3% O2	10.0
CO, ppmvd @ 3% O2	50.0
VOC (as CH4), ppmvd @ 3% O2	10.0
NOx (as NO2), lb/hr	1.8
NOx, lb/MMBtu	0.0112
CO, lb/hr	6.2
CO, lb/MMBtu	0.0385
POC (as CH4), lb/hr	0.7
POC, lb/MMBtu	0.0043
PM10, lb/hr	3.30
PM10, lb/MMBtu	0.0205
SO2, grains/100 scf	0.25
SO2, lb/hr	0.11
SO2, lb/MMBtu	0.0007
NH3, lb/hr	0.76

Table 8.1A-3
Calculation of Cooling Tower Emissions
Central Valley Energy Center

Cooling Tower Design Parameters	
Water Flow Rate, 10E6 lbm/hr	113.54
Water Flow Rate, gal/min	227,163.0
Drift Rate, %	0.0005
Drift, lbm water/hr	567.68
PM10 Emissions based on TDS Level	
TDS level, ppm	1900
PM10, lb/hr	1.08
PM10, tpy	4.72
PM10 Emissions (16 cells)	
PM10 Emissions per cell, lb/hr	0.067
PM10 Emissions per cell, g/s	8.49E-03

Table 8.1A-4
Emergency Generator Performance and Emissions
Central Valley Energy Center

Engine		
Manufacturer		Caterpillar
Model		G3516 LE
Capacity (w/o fan)	kW	1,040
Brake Horsepower	bhp	1,462
Speed	rpm	1,800
Fuel		Natural Gas
Fuel Consumption (LHV)	Btu/bhp-hr	7,899
Fuel Consumption	lb/hr	554.7
Exhaust Flow	acfm	8,317
Stack Velocity	ft/sec	323.80
Exhaust Temperature	deg. F	886
Exhaust Pipe Diameter	in	12
Number of Exhaust Pipes		1
Exhaust Stack Height	ft	10
Operating Profile		
Annual operation	hrs	200
Emissions		
NOx	g/bhp-hr	2
CO	g/bhp-hr	2.1
VOC (non-methane hydrocarb	g/bhp-hr	0.9
PM10	lb/bhp-hr	0.00035
NOx	lb/hr	6.45
CO	lb/hr	6.77
VOC	lb/hr	2.90
PM10	lb/hr	0.52
	gr/scf	0.00280
SO2	lb/hr	0.0090

Table 8.1A-5
Diesel Fire Pump Performance and Emissions
Central Valley Energy Center

Engine		
Manufacturer		Caterpillar
Model		3406B
Useable Horsepower	hp	370
Speed	rpm	1750
Fuel		No. 2 fuel oil
Specific Gravity		0.825
Fuel Sulfur Content	mass %	0.05%
Fuel Consumption	gph	18.3
Exhaust Flow	acfm	2452
Stack Velocity	ft/sec	208.1
Exhaust Temperature	deg. F	1002
Exhaust Pipe Diameter	in	6
Exhaust Stack Height	ft	10
Pump		
Speed	rpm	1750
Capacity	gpm	2500
Discharge Pressure	psig	150
Pump Efficiency	%	0.65
Brake Horsepower	bhp	336.5
Operating Profile		
Annual Operation	hrs	100
Emissions		
Exhaust Velocity	ft/sec	208.1
NOx	g/bhp-hr	5.89
CO	g/bhp-hr	3.55
VOC	g/bhp-hr	0.73
PM10	g/bhp-hr	0.25
NOx	lb/hr	4.36
CO	lb/hr	2.63
VOC	lb/hr	0.54
PM10	lb/hr	0.19
	gr/scf	0.00313
SO2	lb/hr	0.128

Table 8.1A-6
Calculation of Daily and Annual Fuel Use
Central Valley Energy Center

	Operating Hours			Max Hourly Fuel Use, MMBtu
	max. hour	hrs/day	hrs/yr	
Turbine 1, no DB	0	0	3660	1968.5
Turbine 2, no DB	0	0	3660	1968.5
Turbine 3, no DB	0	0	3660	1968.5
Turbine 1, w/ DB	1	24	5100	2623
Turbine 2, w/ DB	1	24	5100	2623
Turbine 3, w/ DB	1	24	5100	2623
Aux Boiler, 100%	1	24	3000	161

	Fuel Use		
	MMBtu/hr	MMBtu/day	MMBtu/yr
Turbine 1, no DB	n/a	0.0	7,204,710
Turbine 2, no DB	n/a	0.0	7,204,710
Turbine 3, no DB	n/a	0.0	7,204,710
Turbine 1, w/ DB	2,623.0	62,952.0	13,377,300
Turbine 2, w/ DB	2,623.0	62,952.0	13,377,300
Turbine 3, w/ DB	2,623.0	62,952.0	13,377,300
Total, Three Trains	**7,869.0**	**188,856.0**	**61,746,030**
Aux Boiler, 100%	161.0	3,864.0	483,000
Total, All Units	**8,030.0**	**192,720.0**	**62,229,030**

Table 8.1A-7a

Summary of Startup Emissions Data - pounds per hour

Project	Notes	POC	CO	NOx	SOx	PM10
Crockett Cogeneration	Source Tests					
6/96 avg	(Note 1)	54	46	59	-	-
6/97 avg		<1	31	41	-	-
min run		<1	27	9	-	-
max run		59	49	95	-	-
Crockett Cogeneration	FDOC (Note 2)	170	385	160	-	-
SF Energy	FDOC	299	437	77	-	-
Sutter	From Westinghouse					
Cold Start		-	838	175	-	-
Hot Start		-	902	170	-	-
Sutter	FDOC					
Cold Start	(Note 3)	1.1	838	175	2.7	9.0
Hot Start		1.1	902	170	2.7	9.0
Westinghouse	Note 4					
Cold Start		292	1722	183	3	28
Warm Start		296	1625	221	3	25
Hot Start		442	2142	217	4	33
Bechtel - DEC	From Westinghouse					
Cold Start		437	3317	168	-	7
Hot Start	Note 5	520	7343	189	-	8
Used in AFC	Note 6					
Cold Start		16	902	80	1.3	11

Notes:

1. Minimum and maximum values are based on the six individual runs that comprise the two sets of tests.
2. Permit conditions have not been carried forward into the permit to operate, and are no longer in effect.
3. Values shown are from the engineering analysis; there are no proposed permit conditions for startup emissions limits in the proposed FDOC.
4. Westinghouse provided data for the total plant (3 turbines) on a lbs/start basis. The above lbs/hr values were calculated assuming a 3 hour starting period per turbine for a cold start; 2 hours for a warm start; and 1 hour for a hot start. Data do not reflect the performance of oxidation catalysts or CO catalysts.
5. Bechtel estimates are 140 minutes for cold start for first engine; 40 minutes for cold start for second and third engines; and 30 minutes for hot start for each engine.
6. POC values are three times full load emission rates. CO values are expected average values. NOx values are 30% higher than the higher of the two Crockett test averages, rounded up to the nearest 5 lbs/hr. SOx and PM10 values are the full load emission rates.

Table 8.1A-7b

Summary of Startup Emissions Data - pounds per start per turbine

Project		Notes	POC	CO	NOx	SOx	PM10
Crockett Cogeneration		Source Tests					
	6/96 avg	(Note 1)	71	62	79	-	-
	6/97 avg		1	41	54	-	-
	min run		<1	36	12	-	-
	max run		79	66	127	-	-
Crockett Cogeneration		FDOC (Note 2)	340	770	320	-	-
SF Energy		FDOC (Note 3)	299	437	77	-	-
Sutter		From Westinghouse					
	Cold Start		-	611	2932	-	-
	Hot Start		-	339	1804	-	-
Sutter		Proposed FDOC (Note 4)					
	Cold Start		3	2514	525	8	27
	Hot Start		1	902	170	3	9
Westinghouse		Note 5					
	Cold Start		875	5167	550	8	83
	Warm Start		592	3250	442	5	50
	Hot Start		442	2142	217	4	33
Bechtel - DEC		From Westinghouse					
	Cold Start		1019	7740	391	-	17
	Hot Start		520	3671	189	-	4
Used in AFC		Note 6					
	Cold Start		48	2706	240	5.5	49.2

Notes:

1. Data extrapolated from reported hourly values by ratio of 80/60.
2. Values based on maximum two hours per startup.
3. Values based on maximum one hour per startup.
4. Values based on maximum three hours per cold start, one hour per hot start.
5. Westinghouse provided data for the total plant (3 turbines). Data do not reflect the performance of oxidation catalysts or CO catalysts.
6. Based on maximum of three hours per startup.

Table 8.1A-8
Detailed Calculations for Maximum Hourly, Daily and Annual Criteria Pollutant Emissions
Central Valley Energy Center

								NOx Emission Rates			SO2	CO Emission Rates			VOC Emission Rates			PM10
		Base Load		Cold Start		Hot Start		Base Load	Cold Start	Hot Start	Emission Rate	Base Load	Cold Start	Hot Start	Base Load	Cold Start	Hot Start	mission Rate
	max. hour	hrs / day	hrs / yr	hrs / day	hrs / yr	hrs / day	hrs / yr	lb / hr	lb / hr	lb / hr	lb / hr	lb / hr	lb / hr	lb / hr	lb / hr	lb / hr	lb / hr	lb / hr
Turbine 1, no DB	0	4	3244	3	156	1	260	17.83	80	80	1.38	26.06	838.0	902.0	3.48	16.0	16.0	11.0
Turbine 2, no DB	0	4	3244	3	156	1	260	17.83	80	80	1.38	26.06	838.0	902.0	3.48	16.0	16.0	11.0
Turbine 3, no DB	0	4	3244	3	156	1	260	17.83	80	80	1.38	26.06	838.0	902.0	3.48	16.0	16.0	11.0
Turbine 1, w / DB&PA	1	16	5100	0	0	0	0	23.77	0	0	1.84	34.73	0	0	6.63	0.0	0.0	16.4
Turbine 2, w / DB&PA	1	16	5100	0	0	0	0	23.77	0	0	1.84	34.73	0	0	6.63	0.0	0.0	16.4
Turbine 3, w / DB&PA	1	16	5100	0	0	0	0	23.77	0	0	1.84	34.73	0	0	6.63	0.0	0.0	16.4
Aux Boiler	1	24	3000	0	0	0	0	1.80	0	0	0.11	6.20	0	0	0.70	0.0	0.0	3.3
Emergency generator	1	1	200	0	0	0	0	6.45	0	0	0.009	6.77	0	0	2.90	0.0	0.0	0.52
Fire pump engine	0.75	0.75	100	0	0	0	0	4.36	0	0	0.1281	2.63	0	0	0.54	0.0	0.0	0.19
Cooling tower	1	24	8760	0	0	0	0	0	0	0	0	0	0	0	0.0	0.0	0.0	1.08

	NOx			SO2			CO			VOC			PM10		
	Max	Max	Total	Max	Max	Total	Max	Max	Total	Max	Max	Total	Max	Max	Total
	lb / hr	lb / day	tpy	lb / hr	lb / day	tpy	lb / hr	lb / day	tpy	lb / hr	lb / day	tpy	lb / hr	lb / day	tpy
Turbine 1, no DB	80.0	391.3	39.8	0.0	0.0	2.5	902.0	3,520.2	224.9	16.0	77.9	9.0	0.0	0.0	20.1
Turbine 2, no DB	0.0	391.3	39.8	0.0	0.0	2.5	0.0	3,520.2	224.9	0.0	77.9	9.0	0.0	0.0	20.1
Turbine 3, no DB	0.0	391.3	39.8	0.0	0.0	2.5	0.0	3,520.2	224.9	0.0	77.9	9.0	0.0	0.0	20.1
Turbine 1, w / DB&PA	0.0	380.3	48.5	1.8	44.1	4.7	0.0	555.7	88.6	0.0	106.1	16.9	16.4	392.4	41.7
Turbine 2, w / DB&PA	23.8	380.3	48.5	1.8	44.1	4.7	34.7	555.7	88.6	6.6	106.1	16.9	16.4	392.4	41.7
Turbine 3, w / DB&PA	23.8	380.3	48.5	1.8	44.1	4.7	34.7	555.7	88.6	6.6	106.1	16.9	16.4	392.4	41.7
Turbines / Duct Burners	127.5	2315.0	264.8	5.5	132.3	21.6	971.5	12,227.8	940.4	29.3	552.0	77.7	49.1	1,177.2	185.5
Aux Boiler	1.8	43.2	2.7	0.11	2.7	0.17	6.2	148.8	9.3	0.7	16.8	1.1	3.30	79.2	5.0
Emergency generator	6.4	6.4	0.6	0.01	0.0	0.00	6.8	6.8	0.7	2.9	2.9	0.3	0.52	0.5	0.05
Fire pump engine	3.3	3.3	0.22	0.10	0.10	0.01	2.0	2.0	0.1	0.4	0.4	0.0	0.14	0.14	0.01
Cooling tower	0.0	0.0	0.0	0.0	0.0	0.00	0.0	0.0	0.0	0.0	0.0	0.0	1.1	25.9	4.7
Total	135.8	2367.9	268.4	5.7	135.1	21.8	984.4	12,385.3	950.5	32.9	572.1	79.0	53.9	1,282.9	195.2
	lb / hr	lb / day	tpy	lb / hr	lb / day	tpy	lb / hr	lb / day	tpy	lb / hr	lb / day	tpy	lb / hr	lb / day	tpy

Assumptions:

Each turbine has one cold start and one hot start on worst case day; startups lag by two hours, but to be conservative, no lag time is assumed.
Boiler operates at full load 24 hrs / day on worst case day.
Emergency generator and fire pump will not both be tested during the same one-hour period. Higher emission rate used for calculating hourly emissions.

Table 8.1A-9a
Calculation of Noncriteria Pollutant Emissions from Gas Turbines
Central Valley Energy Center

Compound (1)	Emission Factor, lb/MMscf (2)	(each turbine) Maximum Hourly Emissions, lb/hr (3)	Annual Emissions, ton/yr (4)	Total, 3 turbines lb/yr	tpy
Ammonia	(5)	35.19	138.06	828,388.8	414.2
Propylene	7.71E-01	1.99	7.82	46,948.9	23.5
Hazardous Air Pollutants					
Acetaldehyde	4.08E-02	0.11	0.41	2,484.5	1.2
Acrolein	3.69E-03	0.01	0.04	224.7	0.1
Benzene	3.33E-03	0.01	0.03	202.8	0.1
1,3-Butadiene	4.39E-04	1.14E-03	4.46E-03	26.7	0.0
Ethylbenzene	3.26E-02	0.08	0.33	1,985.1	1.0
Formaldehyde	1.65E-01	0.43	1.67	10,047.4	5.0
Hexane	2.59E-01	0.67	2.63	15,771.4	7.9
Naphthalene	1.33E-03	3.44E-03	1.35E-02	81.0	0.0
PAHs:	--	--	--	--	--
Anthracene	3.38E-05	8.74E-05	3.43E-04	2.1	0.0
Benzo(a)anthracene	2.26E-05	5.85E-05	2.29E-04	1.4	0.0
Benzo(a)pyrene	1.39E-05	3.60E-05	1.41E-04	0.8	0.0
Benzo(b)fluoranthrene	1.13E-05	2.92E-05	1.15E-04	0.7	0.0
Benzo(k)fluoranthrene	1.10E-05	2.85E-05	1.12E-04	0.7	0.0
Chrysene	2.52E-05	6.52E-05	2.56E-04	1.5	0.0
Dibenz(a,h)anthracene	2.35E-05	6.08E-05	2.38E-04	1.4	0.0
Indeno(1,2,3-cd)pyrene	2.35E-05	0.00	0.00	1.4	0.0
Propylene Oxide	2.96E-02	0.08	0.30	1,802.4	0.9
Toluene	1.33E-01	0.34	1.35	8,098.8	4.0
Xylene	6.53E-02	0.17	0.66	3,976.3	2.0
Total HAPs			7.45	44,711.3	22.36

Notes:

(1) From AP-42 and CATEF databases. See text.
(2) Based on maximum hourly turbine fuel use of 2623 MMBtu/hr (with duct burner) a fuel HHV of 1014 Btu/scf. 2.59
(3) Based on maximum annual turbine fuel use of 20,582,010 MMBtu/yr (with duct bu and fuel HHV of 1014 Btu/scf. 20,298
(4) Based on 10 ppm ammonia slip from SCR system.

Table 8.1A-9b
Calculation of Noncriteria Pollutant Emissions from Auxiliary Boiler
Central Valley Energy Center

Compound	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr (2)	Annual Emissions, lb/yr (3)	Annual Emissions, ton/yr (3)
Ammonia	(4)	0.76	2280.0	1.14E+00
Propylene	1.55E-02	2.47E-03	7.4	3.70E-03
Hazardous Air Pollutants				
Acetaldehyde	9.0E-04	1.43E-04	0.43	2.14E-04
Acrolein	8.00E-04	1.27E-04	0.38	1.91E-04
Benzene	1.70E-03	2.70E-04	0.81	4.05E-04
Ethylbenzene	2.00E-03	3.18E-04	0.95	4.76E-04
Formaldehyde	3.60E-03	5.72E-04	1.7	8.57E-04
Hexane	1.3E-03	2.06E-04	0.62	3.10E-04
Naphthalene	3.00E-04	4.76E-05	0.14	7.14E-05
PAHs (4)	1.00E-04	1.59E-05	0.05	2.38E-05
Toluene	7.8E-03	1.24E-03	3.72	1.86E-03
Xylene	5.8E-03	9.21E-04	2.76	1.38E-03
Total HAPs				5.79E-03

Notes:
(1) Emission factors from Ventura County APCD.
(2) Based on maximum hourly boiler fuel use of 161 MMBtu/hr and fuel HHV of 1014 Btu/scf. 0.16 MMscf/hr
(3) Based on maximum annual boiler fuel use of 483,000 MMBtu/yr and fuel HHV of 1014 Btu/scf. 476.33 MMscf/yr
(4) Based on 10 pppm ammonia slip.
(5) Polycyclic aromatic hydrocarbons, excluding naphthalene (modeled separately).

Table 8.1A-9c
Calculation of Noncriteria Pollutant Emissions from Cooling Tower (1)
Central Valley Energy Center

Constituent	Concentration in Cooling Tower Return Water (2)		Emissions, lb/hr	Emissions, ton/yr	Emissions, lbs/year
Aluminum	0	ppm	0.00E+00	0.00E+00	0.0
Ammonia	0	ppm	0.00E+00	0.00E+00	0.0
Copper	0.032	ppm	1.82E-05	7.96E-05	0.2
Silver	0	ppm	0.00E+00	0.00E+00	0.0
Zinc	0.068	ppm	3.86E-05	1.69E-04	0.3
Hazardous Air Pollutants					
Arsenic	0.08	ppm	4.54E-05	1.99E-04	0.398
Cadmium	0	ppm	0.00E+00	0.00E+00	0.000
Chromium (III)	0	ppm	0.00E+00	0.00E+00	0.000
Cyanide	0	ppm	0.00E+00	0.00E+00	0.000
Lead	0.012	ppm	6.81E-06	2.98E-05	0.060
Mercury	0	ppm	0.00E+00	0.00E+00	0.000
Nickel	0.068	ppm	3.86E-05	1.69E-04	0.338
Dioxins/furans	--	ppm	--	--	--
PAHs	--		--	--	--
Total HAPs				3.98E-04	0.80

Notes:
(1) Emissions calculated from maximum drift rate of 567.68 lb/hr
(2) Four cycles of concentration.

APPENDIX 8.1B

Modeling Analysis

Figure 8.1B-1

Building Layout for GEP Analysis

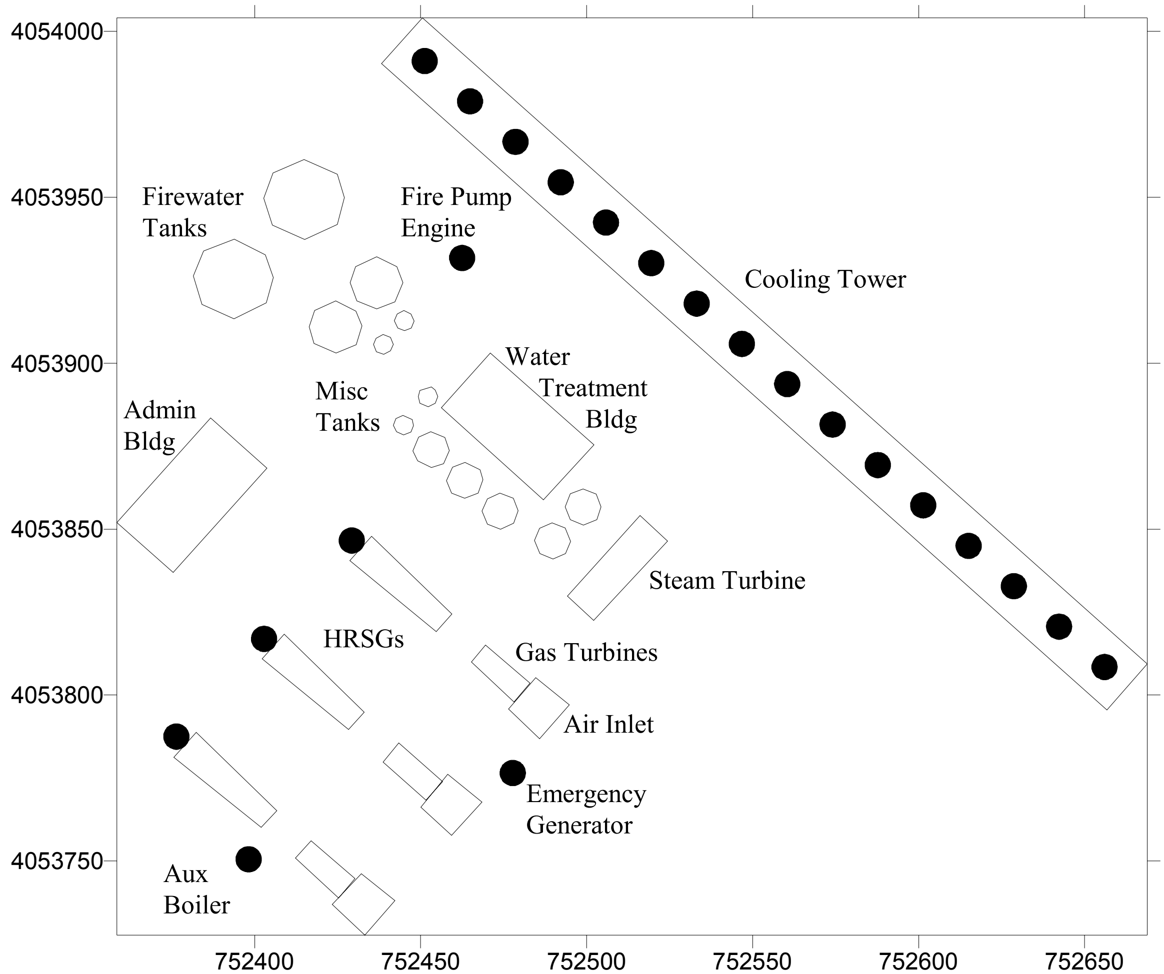

Table 8.1B-1
Building Dimensions Used in GEP Analysis

Building/Structure	Height, feet	Length, feet	Width, feet
Heat Recovery Steam Generators	92	132	33
Turbines	32	69	26
Air Inlets	65	42.2	44.6
Cooling Tower	45	957	67
Water Treatment Bldg	26	137	71
Steam Turbine	47	109	38
Administration Bldg	40	140.4	75
Fire Water Tanks	40	80.6 (diameter)	
Brine Concentrator Tank	90	20 (diameter)	
Misc. Tanks	30	52 (diameter)	

Table 8.1B-2
Emissions and Stack Parameters for Screening Modeling
Central Valley Energy Center

Turbine Case	Load/ Ambient Temp	Duct Firing?	Stack Diam (m)	Stack Height (m)	Exhaust Temp (deg K)	Exhaust Velocity (m/s)	NOx, g/s	SO2, g/s	CO, g/s	PM10, g/s
1	100/100F	yes	5.639	44.196	348.556	19.133	2.995	0.231	4.376	2.060
2	70/100F	no	5.639	44.196	351.889	14.964	1.448	0.112	2.116	1.386
3	100/61F	no	5.639	44.196	362.444	19.601	2.131	0.165	3.112	1.386
4	100/32F	no	5.639	44.196	359.111	20.260	2.247	0.174	3.284	1.386
5	70/32F	no	5.639	44.196	360.778	16.820	1.680	0.131	2.453	1.386

Note: Parameters are for each turbine.

Table 8.1B-3
Results of Turbine Screening Modeling
Central Valley Energy Center

Turbine Emission Rates for Screening Modeling (g/s)				
Turbine Case	NO_X 1-hr	SO_2 1-hr	CO 1-hr	PM_{10} 1-hr
1	2.995	0.231	4.376	2.060
2	1.448	0.112	2.116	1.386
3	2.131	0.165	3.112	1.386
4	2.242	0.174	3.276	1.386
5	1.680	0.131	2.453	1.386

Turbine Case	Load/ Ambient Temp.	Modeled Impacts by Pollutant and Averaging Period (ug/m^3)									
		NO_X		SO_2				CO		PM_{10}	
		1-hr	annual	1-hr	3-hr	24-hr	annual	1-hr	8-hr	24-hr	annual
1	100/100F	**18.06**	**0.143**	**1.395**	**0.533**	**0.1123**	**0.01106**	**26.38**	**4.54**	**0.999**	0.0984
2	70/100F	9.50	0.118	0.735	0.330	0.0781	0.00909	13.89	3.08	0.967	**0.1125**
3	100/61F	12.34	0.084	0.956	0.342	0.0685	0.00647	18.03	3.01	0.576	0.0543
4	100/32F	12.88	0.084	0.999	0.351	0.0722	0.00650	18.83	3.14	0.575	0.0518
5	70/32F	10.40	0.099	0.811	0.328	0.0706	0.00771	15.19	2.74	0.746	0.0815

Turbine Case	Max Impact per 4.0 g/s (ug/m^3)				
	1-hr	3-hr	8-hr	24-hr	annual
1	6.029	2.304	1.038	0.485	0.048
2	6.565	2.952	1.458	0.698	0.081
3	5.793	2.071	0.966	0.415	0.039
4	5.747	2.019	0.959	0.415	0.037
5	6.190	2.506	1.117	0.539	0.059

Table 8.1B-4
Central Valley Energy Center
Emergency Generator and Fire Pump Screening Analysis

Emission Rates (lb/hr)

	NOx 1-hr	SO2 1-hr	CO 1-hr
Fire pump (1)	3.271	0.096	1.97
Generator	6.446	8.97E-03	6.77

Modeled Unit Impacts (ug/m3 per g/s)
(highest result from 5 yrs of met data)

	all receptors 1-hr
Fire Pump	2184.05
Generator	673.14

Max. Modeled Concentrations

	NOx		SO2	CO
	1-hr	1-hr w/ OLM	1-hr	1-hr
Fire pump	900.1	227.2	**26.4**	542.5
Generator	546.7	**230.72**	0.8	**574.1**

Note (1): Fire pump will operate only 45 minutes out of every hour, so hourly emission rates are adjusted by 45/60 or 0.75 for modeling.

Table 8.1B-5
Emission Rates and Stack Parameters for Modeling
Central Valley Energy Center Gas Turbines and Other Equipment

	Stack Diam, m	Stack Height, m	Exh Temp, Deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rate, g/s NOx	SO2	CO	PM10
Averaging Period: One hour									
Turbine 1/HRSG	5.639	44.196	348.6	477.8	19.133	2.995	0.231	4.376	n/a
Turbine 2/HRSG	5.639	44.196	348.6	477.8	19.133	2.995	0.231	4.376	n/a
Turbine 3/HRSG	5.639	44.196	348.6	477.8	19.133	2.995	0.231	4.376	n/a
Aux Boiler	1.067	36.576	435.8	22.96	25.685	0.227	1.420E-02	0.781	n/a
Em Generator (1)	0.305	3.048	747.4	3.93	53.795	0.812	n/a	0.853	n/a
Fire Pump (1,2)	0.152	3.048	811.9	1.16	63.439	n/a	1.211E-02	n/a	n/a
Cooling Tower (3)	10.668	17.983	294.1	903.5	10.108	n/a	n/a	n/a	n/a
Averaging Period: Three hours									
Turbine 1/HRSG	5.639	44.196	348.6	477.8	19.133	n/a	0.231	n/a	n/a
Turbine 2/HRSG	5.639	44.196	348.6	477.8	19.133	n/a	0.231	n/a	n/a
Turbine 3/HRSG	5.639	44.196	348.6	477.8	19.133	n/a	0.231	n/a	n/a
Aux Boiler	1.067	36.576	435.8	23.0	25.685	n/a	1.420E-02	n/a	n/a
Em Generator	0.305	3.048	747.4	3.9	53.795	n/a	3.765E-04	n/a	n/a
Fire Pump (2)	0.152	3.048	811.9	1.2	63.439	n/a	4.035E-03	n/a	n/a
Cooling Tower (3)	10.668	17.983	294.1	903.5	10.108	n/a	n/a	n/a	n/a
Averaging Period: Eight hours									
Turbine 1/HRSG	5.639	44.196	348.6	477.8	19.133	n/a	n/a	42.330	n/a
Turbine 2/HRSG	5.639	44.196	348.6	477.8	19.133	n/a	n/a	42.330	n/a
Turbine 3/HRSG	5.639	44.196	348.6	477.8	19.133	n/a	n/a	42.330	n/a
Aux Boiler	1.067	36.576	435.8	23.0	25.685	n/a	n/a	0.781	n/a
Em Generator	0.305	3.048	747.4	3.9	53.795	n/a	n/a	0.107	n/a
Fire Pump (2)	0.152	3.048	811.9	1.2	63.439	n/a	n/a	3.105E-02	n/a
Cooling Tower (3)	10.668	17.983	294.1	903.5	10.108	n/a	n/a	n/a	n/a
Averaging Period: 24 hours; 24-hr duct firing scenario									
Turbine 1/HRSG	5.639	44.196	348.6	477.8	19.133	n/a	0.231	n/a	2.060
Turbine 2/HRSG	5.639	44.196	348.6	477.8	19.133	n/a	0.231	n/a	2.060
Turbine 3/HRSG	5.639	44.196	348.6	477.8	19.133	n/a	0.231	n/a	2.060
Aux Boiler (3)	1.067	36.576	435.8	23.0	25.685	n/a	1.420E-02	n/a	0.416
Em Generator	0.305	3.048	747.4	3.9	53.795	n/a	4.707E-05	n/a	2.709E-03
Fire Pump (2)	0.152	3.048	811.9	1.2	63.439	n/a	5.044E-04	n/a	9.719E-04
Cooling Tower (3)	10.668	17.983	294.1	903.5	10.108	n/a	n/a	n/a	8.494E-03
Averaging Period: Annual, NO2 and SO2									
Turbine 1/HRSG	5.639	44.196	348.6	477.8	19.133	2.538	0.207	n/a	n/a
Turbine 2/HRSG	5.639	44.196	348.6	477.8	19.133	2.538	0.207	n/a	n/a
Turbine 3/HRSG	5.639	44.196	348.6	477.8	19.133	2.538	0.207	n/a	n/a
Aux Boiler (4)	1.067	36.576	435.8	22.96	25.685	7.767E-02	4.863E-03	n/a	n/a
Em Generator	0.305	3.048	747.4	3.93	53.795	1.854E-02	2.579E-05	n/a	n/a
Fire Pump (2)	0.152	3.048	811.9	1.16	63.439	6.273E-03	1.843E-04	n/a	n/a
Cooling Tower (3)	10.668	17.983	294.1	903.5	10.108	n/a	n/a	n/a	n/a
Averaging Period: Annual, PM10									
Turbine 1/HRSG	5.639	44.196	351.9	373.7	14.964	n/a	n/a	n/a	1.778
Turbine 2/HRSG	5.639	44.196	351.9	373.7	14.964	n/a	n/a	n/a	1.778
Turbine 3/HRSG	5.639	44.196	351.9	373.7	14.964	n/a	n/a	n/a	1.778
Aux Boiler (4)	1.067	36.576	435.8	22.96	25.685	n/a	n/a	n/a	0.142
Em Generator (5)	0.305	3.048	747.4	3.93	53.795	n/a	n/a	n/a	1.485E-03
Fire Pump (2)	0.152	3.048	811.9	1.16	63.439	n/a	n/a	n/a	2.663E-04
Cooling Tower (3)	10.668	17.983	294.1	903.5	10.108	n/a	n/a	n/a	8.494E-03

NOTE:
1. Emergency generator and fire pump will not operate during the same 1-hr period. Unit with higher one-hour impacts included in one-hour impacts for facility.
2. Fire pump engine operation will be limited to 45 minutes out of any hour and 100 hours per year.
3. Cooling tower parameters based on each cell; total of 16 cells.
4. Auxiliary boiler operates at full load 24 hrs/day on worst case day; 3000 hrs/yr.
5. Emergency generator operation will be limited to 200 hours per year.

Table 8.1B-6
Fumigation Screening Analysis
Central Valley Energy Center

Emission Rates for Unit Impacts Analysis (g/sec per stack)				
	TURBINES	BOILER	FIREPUMP	EMER.GEN
NOx	8.985	0.227	0.812	0
SO2	0.694	0.0142	0	0.0121
CO	13.128	0.781	0.853	0

Modeled Maximum 1-Hr Avg Concs at Turbine Fumigation Location (ug/m3)					
	TURBINES	BOILER	FIREPUMP	EMER.GEN	TOTAL
ug/m3 for 1 g/s/stack	1.389	3.197	13.39	13.74	
NOx (ug/m3)	12.480	0.725	10.876	0.000	24.1
SO2 (ug/m3)	0.965	0.045	0.000	0.166	1.18
CO (ug/m3)	18.235	2.497	11.419	0.000	32.2
Max.Impact Dist (m)	14,816				

Modeled Maximum 1-Hr Avg Concs at Aux Boiler Fumigation Location (ug/m3)					
	TURBINES	BOILER	FIREPUMP	EMER.GEN	TOTAL
ug/m3 for 1 g/s/stack	N/A	6.667	50.36	52.31	
NOx (ug/m3)	N/A	1.51	40.90	0.00	42.4
SO2 (ug/m3)	N/A	0.09	0.00	0.63	0.73
CO (ug/m3)	N/A	5.21	42.95	0.00	48.2
Max.Impact Dist (m)	4,655				

NOTES TO TABLE 8.1B-6

FUMIGATION IMPACTS ANALYSIS

INVERSION BREAKUP FUMIGATION

Inversion breakup fumigation is generally a short-term phenomenon and was evaluated here as persisting for up to one hour. SCREEN3 was used to model one-hour unit impacts from the turbines/HRSGs and the auxiliary boiler under 2.5 m/s winds and F stability (for fumigation impacts) and under all meteorological conditions (shown in the table as "Max. 1-hr Unit Impact from SCREEN3").

Fumigation impacts for the turbines/HRSGs and the auxiliary boiler were predicted to occur at 14.8 and 4.7 km from the facility, respectively. SCREEN3 predicted no fumigation impacts from the emergency generator or the fire pump engine, due to their short stacks. Maximum impacts for other sources at the locations of fumigation impacts were determined using SCREEN3 with flat terrain and the full SCREEN3 meteorological dataset. Note that since the distance to the fumigation impact for the turbines/HRSGs is greater than the distance to the fumigation impact for the auxiliary boiler, the turbines/HRSGs would not contribute to fumigation impacts due to the auxiliary boiler.

The modeled one-hour average fumigation impacts for the combined sources (three turbines and auxiliary boiler plus the emergency generator or fire pump engine, whichever had greater emissions) are shown in Table 8.1B-6. The summary of modeling results in Table 8.1-26 shows that fumigation impacts are much lower than the maximum modeled impacts determined using ISCST3, indicating that maximum ground-level impacts from the project will not occur under fumigation conditions.

Table 8.1B-7
Modeled Impacts During Turbine Startup
Central Valley Energy Center
Assume one turbine in startup, two turbines at peak load.

	Stack Diam, m	Stack Height, m	Exh Temp, Deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rate, g/s			
						NOx	SO2	CO	PM10
Averaging Period: One hour									
Turbine 1/HRSG	5.64	44.20	351.9	373.7	14.96	30.240	0.112	113.652	n/a
Turbine 2/HRSG	5.64	44.20	348.6	477.8	19.13	2.995	0.231	4.376	n/a
Turbine 3/HRSG	5.64	44.20	348.6	477.8	19.13	2.995	0.231	4.376	n/a

Averaging Period	Pollutant	Modeled Impact, ug/m3
1 hour	NOx (1)	132.8
	SO2	3.7
	CO	1080.4

Notes: (1) With ozone limiting.

APPENDIX 8.1C

Protocol for Increments Analysis

Figure 8.1C-1

Locations of Maximum Acute, Chronic and Cancer Risks

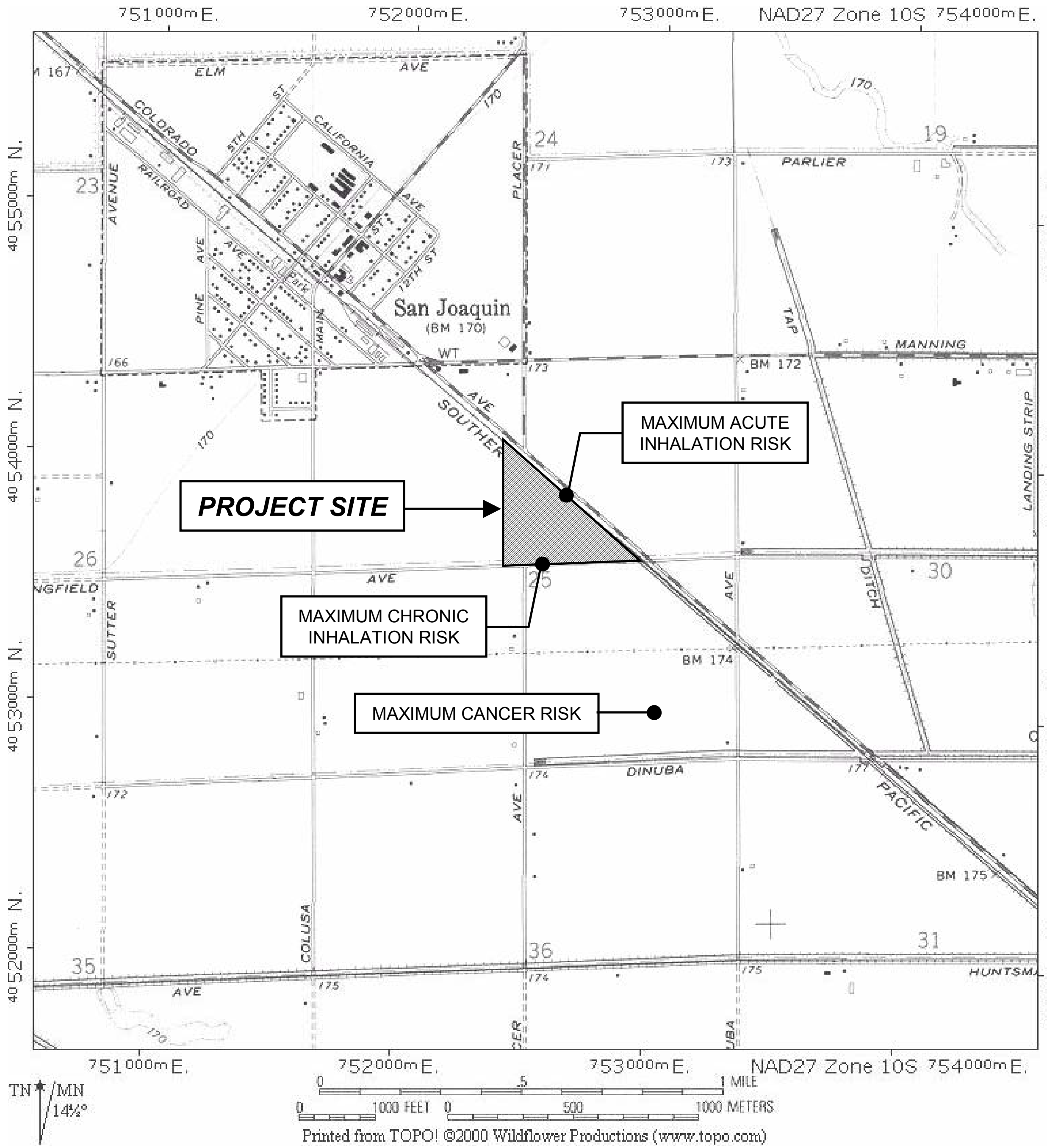

Table 8.1C-1
Calculation of Screening HRA Inputs for Gas Turbines

		Emission Rates (each turbine)				Acute Inhalation		Chronic Inhalation		Cancer Risk		
Chemical	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr (2)	Annual Emissions, ton/yr (3)	One-hour Impacts, g/s	Annual Impacts, g/s	REL (ug/m3)	Weighted Contribution to Acute HHI (g/s per ug/m3)	REL (ug/m3)	Weighted Contribution to Chronic HHI (g/s per ug/m3)	URV (ug/m3)-1	Multipathway Factor	Weighted Contribution to Cancer Risk (g/s per ug/m3)
Ammonia	(4)	30.06	113.71	3.79E+00	3.27E+00	3.20E+03	1.18E-03	200	1.64E-02	--	--	--
Propylene	7.71E-01	1.99	7.68	2.51E-01	2.21E-01	--	--	3000	7.37E-05	--	--	--
Hazardous Air Pollutants												
Acetaldehyde	4.08E-02	0.11	0.41	1.33E-02	1.17E-02	--	--	9	1.30E-03	2.70E-06	1	3.16E-08
Acrolein	3.69E-03	0.01	0.04	1.20E-03	1.06E-03	1.90E-01	6.33E-03	0.06	1.76E-02	--	--	--
Benzene	3.33E-03	0.01	0.03	1.09E-03	9.54E-04	1.30E+03	8.35E-07	60	1.59E-05	2.90E-05	1	2.77E-08
1,3-Butadiene	4.39E-04	1.14E-03	4.37E-03	1.43E-04	1.26E-04	--	--	20	6.29E-06	1.70E-04	1	2.14E-08
Ethylbenzene	3.26E-02	0.08	0.32	1.06E-02	9.34E-03	--	--	2000	4.67E-06	--	--	--
Formaldehyde	1.65E-01	0.43	1.64	5.38E-02	4.73E-02	9.40E+01	5.72E-04	3	1.58E-02	6.00E-06	1	2.84E-07
Hexane	2.59E-01	0.67	2.58	8.44E-02	7.42E-02	--	--	7000	1.06E-05	--	--	--
Naphthalene	1.33E-03	3.44E-03	1.33E-02	4.33E-04	3.81E-04	--	--	9	4.24E-05	--	--	--
PAHs:	--	--	--	--	--	--	--	--	--	--	--	--
Anthracene	3.38E-05	8.74E-05	3.37E-04	1.10E-05	9.69E-06	--	--	--	--	--	--	--
Benzo(a)anthracene	2.26E-05	5.85E-05	2.25E-04	7.37E-06	6.48E-06	--	--	--	--	1.10E-04	3.455	2.46E-09
Benzo(a)pyrene	1.39E-05	3.60E-05	1.38E-04	4.53E-06	3.98E-06	--	--	--	--	1.10E-03	3.455	1.51E-08
Benzo(b)fluoranthrene	1.13E-05	2.92E-05	1.13E-04	3.68E-06	3.24E-06	--	--	--	--	1.10E-04	3.455	1.23E-09
Benzo(k)fluoranthrene	1.10E-05	2.85E-05	1.10E-04	3.59E-06	3.15E-06	--	--	--	--	1.10E-04	3.455	1.20E-09
Chrysene	2.52E-05	6.52E-05	2.51E-04	8.21E-06	7.22E-06	--	--	--	--	1.10E-05	3.455	2.74E-10
Dibenz(a,h)anthracene	2.35E-05	6.08E-05	2.34E-04	7.66E-06	6.74E-06	--	--	--	--	1.20E-03	3.455	2.79E-08
Indeno(1,2,3-cd)pyrene	2.35E-05	6.08E-05	2.34E-04	7.66E-06	6.74E-06	--	--	--	--	1.10E-04	3.455	2.56E-09
Propylene Oxide	2.96E-02	7.66E-02	2.95E-01	9.65E-03	8.48E-03	3.10E+03	3.11E-06	30	2.83E-04	3.70E-06	1	3.14E-08
Toluene	1.33E-01	0.34	1.33	4.33E-02	3.81E-02	3.70E+04	1.17E-06	300	1.27E-04	--	--	--
Xylene	6.53E-02	0.17	0.65	2.13E-02	1.87E-02	2.20E+04	9.67E-07	700	2.67E-05	--	--	--
						Acute Risk Factor	8.09E-03	Chronic Risk Factor	5.16E-02	Cancer Risk Factor		4.47E-07

Notes:

(1) From AP-42 and CATEF databases and source tests.
(2) Maximum hourly turbine fuel use: 2.59 MMscf/hr
(3) Maximum annual turbine fuel use: 19,928 MMscf/yr
(4) Based on 10 ppm ammonia slip from SCR system.

Table 8.1C-2
Calculation of Screening HRA Inputs for Auxiliary Boiler

		Emission Rates (each boiler)				Acute Inhalation		Chronic Inhalation		Cancer Risk		
Chemical	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr (2)	Annual Emissions, ton/yr (3)	One-hour Impacts, g/s	Annual Impacts, g/s	REL (ug/m3)	Weighted Contribution to Acute HHI (g/s per ug/m3)	REL (ug/m3)	Weighted Contribution to Chronic HHI (g/s per ug/m3)	URV (ug/m3)-1	Multipathway Factor	Weighted Contribution to Cancer Risk (g/s per ug/m3)
Ammonia	(4)	0.76	1.14	9.576E-02	3.279E-02	3.20E+03	2.993E-05	200	1.640E-04	--	--	--
Propylene	5.30E-01	8.42E-02	1.26E-01	1.060E-02	3.631E-03	--	--	3000	1.210E-06	--	--	--
Hazardous Air Pollutants												
Acetaldehyde	9.0E-04	1.43E-04	2.14E-04	1.801E-05	6.166E-06	--	--	9	6.851E-07	2.70E-06	1	1.665E-11
Acrolein	8.00E-04	1.27E-04	1.91E-04	1.600E-05	5.481E-06	1.90E-01	8.424E-05	0.06	9.135E-05	--	--	--
Benzene	1.70E-03	2.70E-04	4.05E-04	3.401E-05	1.165E-05	1.30E+03	2.616E-08	60	1.941E-07	2.90E-05	1	3.378E-10
Ethylbenzene	2.00E-03	3.18E-04	4.76E-04	4.001E-05	1.370E-05	--	--	2000	6.851E-09	--	--	--
Formaldehyde	3.50E-03	5.56E-04	8.34E-04	7.002E-05	2.398E-05	9.40E+01	7.449E-07	3	7.993E-06	6.00E-06	1	1.439E-10
Hexane	1.3E-03	2.06E-04	3.10E-04	2.601E-05	8.907E-06	--	--	7000	1.272E-09	--	--	--
Naphthalene	3.00E-04	4.76E-05	7.14E-05	6.002E-06	2.055E-06	--	--	9	2.284E-07	--	--	--
PAHs (4)	1.00E-04	1.59E-05	2.38E-05	2.001E-06	6.851E-07	--	--	--	--	1.10E-03	3.455	2.604E-09
Toluene	7.8E-03	1.24E-03	1.86E-03	1.560E-04	5.344E-05	3.70E+04	4.217E-09	300	1.781E-07	--	--	--
Xylene	5.8E-03	9.21E-04	1.38E-03	1.160E-04	3.974E-05	2.20E+04	5.274E-09	700	5.677E-08	--	--	--
Total HAPs			5.76E-03			Acute Risk Factor	1.149E-04	Chronic Risk Factor	2.659E-04	Cancer Risk Factor		3.102E-09

Notes:
(1) Emission factors from Ventura County APCD.
(2) Polycyclic aromatic hydrocarbons, excluding naphthalene (modeled separately). Use benzo(a)pyrene risk factors.

Table 8.1C-3
Calculation of Screening HRA Inputs for Cooling Tower

			Emission Rates for Modeling (each cell)		Acute Inhalation		Chronic Inhalation		Chronic Noninhalation			Cancer Risk		
Chemical	Concentration in Cooling Tower Return Water (2)	Emissions, lb/hr	One-hour Em Rate, g/s	Annual Em Rate, g/s	REL (ug/m3)	Weighted Contribution to Acute HHI (g/s per ug/m3)	REL (ug/m3)	Weighted Contribution to Chronic HHI (g/s per ug/m3)	Avg. Dose (mg/kg-d per ug/m3)	REL (mg/kg-d)	Avg Dose/REL (g/s per ug/m3)	URV (ug/m3)-1	Multipathway Factor	Weighted Contribution to Cancer Risk (g/s per ug/m3)
Aluminum	0 ppm	0.00E+00	0.00E+00	0.00E+00	--	--	--	--	--	--	--	--	--	--
Ammonia	0 ppm	0.00E+00	0.00E+00	0.00E+00	3.20E+03	0.00E+00	200	0.00E+00	--	--	--	--	--	--
Copper	0.032 ppm	1.82E-05	1.43E-07	1.43E-07	1.00E+02	1.43E-09	--	--	--	--	--	--	--	--
Silver	0 ppm	0.00E+00	0.00E+00	0.00E+00	--	--	--	--	--	--	--	--	--	--
Zinc	0.068 ppm	3.86E-05	3.04E-07	3.04E-07	--	--	--	--	--	--	--	--	--	--
Hazardous Air Pollutants														
Arsenic	0.08 ppm	4.54E-05	3.58E-07	3.58E-07	1.90E-01	1.88E-06	0.03	1.19E-05	2.66E-03	2.00E-03	4.76E-07	3.30E-03	2.207	2.39E-04
Cadmium	0 ppm	0.00E+00	0.00E+00	0.00E+00	--	--	0.02	0.00E+00	2.71E-03	1.00E-03	0.00E+00	4.20E-03	1.00	0.00E+00
Chromium (III)	0 ppm	0.00E+00	0.00E+00	0.00E+00	--	--	--	--	--	--	--	--	--	--
Cyanide	0 ppm	0.00E+00	0.00E+00	0.00E+00	3.40E+02	0.00E+00	9	0.00E+00	--	--	--	--	--	--
Lead	0.012 ppm	6.81E-06	5.36E-08	5.36E-08	--	--	--	--	2.66E-03	--	--	1.20E-05	2.881	1.29E-02
Mercury	0 ppm	0.00E+00	0.00E+00	0.00E+00	1.80E+00	0.00E+00	0.09	0.00E+00	3.15E-03	--	--	--	--	--
Nickel	0.068 ppm	3.86E-05	3.04E-07	3.04E-07	6.00E+00	5.07E-08	0.05	6.08E-06	--	--	--	2.60E-04	1.00	1.17E-03
					Acute Risk Factor	1.934E-06	Chronic Risk Factor	1.800E-05	Chronic Noninhalation Risk Factor		4.757E-07	Cancer Risk Factor		1.429E-02

Table 8.1C-4
Calculation of Screening HRA Inputs for Natural Gas Emergency Generator

				Acute Inhalation		Chronic Inhalation		Cancer Risk		
Compound	Emission Factor lb/MMscf (1)	Hourly Emissions g/s (2)	Annual Emissions g/s (3)	REL (ug/m3)	Weighted Contribution to Acute HHI (g/s per ug/m3)	REL (ug/m3)	Weighted Contribution to Chronic HHI (g/s per ug/m3)	URV (ug/m3)-1	Multipathway Factor	Weighted Contribution to Cancer Risk (g/s per ug/m3)
Acetaldehyde	5.29E-01	7.59E-04	1.73E-05	--	--	9	1.93E-06	2.70E-06	1	4.68E-11
Acrolein	5.90E-02	8.47E-05	1.93E-06	1.90E-01	4.46E-04	0.06	3.22E-05	--	--	--
Benzene	2.18E-01	3.13E-04	7.14E-06	1.30E+03	2.41E-07	60	1.19E-07	2.90E-05	1	2.07E-10
1,3-Butadiene	3.67E-01	5.27E-04	1.20E-05	--	--	20	6.01E-07	1.70E-04	1	2.04E-09
Ethyl benzene	7.11E-02	1.02E-04	2.33E-06	--	--	2000	1.16E-09	--	--	--
Formaldehyde	4.71E+00	6.76E-03	1.54E-04	9.40E+01	7.19E-05	3	5.14E-05	6.00E-06	1	9.26E-10
PAHs										
Naphthalene	2.51E-02	3.60E-05	8.22E-07	--	--	9	9.14E-08	--	--	--
Benz(a)anthracene	5.88E-05	8.44E-08	1.93E-09	--	--	--	--	1.10E-04	3.455	7.32E-13
Benzo(b)fluoroanthene	4.09E-05	5.87E-08	1.34E-09	--	--	--	--	1.10E-04	3.455	5.09E-13
Benzo(k)fluoroanthene	7.83E-06	1.12E-08	2.57E-10	--	--	--	--	1.10E-04	3.455	9.75E-14
Benzo(a)pyrene	2.70E-06	3.87E-09	8.85E-11	--	--	--	--	1.10E-03	3.455	3.36E-13
Toluene	2.39E-01	3.43E-04	7.83E-06	3.70E+04	9.27E-09	300	2.61E-08	--	--	--
Xylenes	6.46E-01	9.27E-04	2.12E-05	2.20E+04	4.21E-08	700	3.02E-08	--	--	--
				Acute Risk Factor	5.18E-04	Chronic Risk Factor	8.64E-05	Cancer Risk Factor		3.23E-09

Notes:

(1) CATEF emission factors
(2) Based on maximum hourly fuel use of 11.5 MMBtu/hr (0.011 MMscf/hr)
(3) Based on 0 operating hours per year

Table 8.1C-5
Summary of Modeling Input Values for Screening HRA

Unit	Acute Risk	Chronic Inhalation Risk	Chronic Noninhalation Risk	Cancer Risk
Turbines (each)	8.092E-03	5.164E-02	0.0	4.47E-07
Aux Boiler	1.149E-04	2.659E-04	0.0	3.10E-09
Cooling Tower (each cell)	1.934E-06	1.800E-05	4.757E-07	1.43E-02
Natural Gas Generator	5.178E-04	8.645E-05	0.0	3.23E-09
Diesel Engine	n/a	1.996E-02	0.0	2.99E-05

APPENDIX 8.1D

Screening Health Risk Assessment

APPENDIX 8.1D

CONSTRUCTION PHASE IMPACTS

8.1D.1 Onsite Construction

Construction of the Project is expected to last approximately 24 months. The onsite construction will be performed in the following five main phases:

- Site preparation;
- Foundation work;
- Installation of major equipment;
- Construction/installation of major structures; and
- Start up and commissioning.

Site preparation includes clearing, grading, excavation of footings and foundations, and backfilling operations. After site preparation is finished, the construction of the foundations and structures is expected to begin. Once the foundations and structures are finished, installation and assembly of the mechanical and electrical equipment are scheduled to commence.

Fugitive dust emissions from the construction of the Project will result from:

- Dust entrained during site preparation and grading/excavation at the construction site;
- Dust entrained during onsite travel on paved and unpaved surfaces;
- Dust entrained during aggregate and soil loading and unloading operations; and
- Wind erosion of areas disturbed during construction activities.

Combustion emissions during construction will result from:

- Exhaust from the Diesel construction equipment used for site preparation, grading, excavation, and construction of onsite structures;
- Exhaust from water trucks used to control construction dust emissions;
- Exhaust from Diesel-powered welding machines, electric generators, air compressors, water pumps, etc.;
- Exhaust from Diesel trucks used to deliver concrete, fuel, and construction supplies to the construction site; and
- Exhaust from automobiles and trucks used by workers to commute to the construction site.

To determine the potential worst-case daily construction impacts, exhaust and dust emission rates have been evaluated for each source of emissions. Worst-case daily dust emissions are expected to occur during month seven of the construction schedule; worst-case daily exhaust emissions are expected to occur during month 16. Annual emissions are based on the average equipment mix during the 24-month construction period.

8.1D.2 Natural Gas/Wastewater Pipelines and Transmission Lines

The installation of a 20-mile long natural gas pipeline will generate short-term construction impacts including fugitive dust and construction equipment combustion emissions. For this pipeline route, the excavation, installation of pipe, backfilling, and site cleanup will be performed in approximately 500-foot-long sections over a short duration to minimize fugitive dust and construction equipment combustion emissions.

The installation of the water pipeline will also generate short-term construction impacts including fugitive dust and construction equipment combustion emissions.

The proposed project also includes the installation of a 0.5-mile long transmission line interconnect. As with the construction of the natural gas and water pipelines, this construction activity will result in fugitive dust and construction equipment combustion emissions.

8.1D.3 Available Mitigation Measures

The following mitigation measures are proposed to control exhaust emissions from the Diesel heavy equipment used during construction of the Project:

- Operational measures, such as limiting engine idling time and shutting down equipment when not in use;
- Regular preventive maintenance to prevent emission increases due to engine problems;
- Use of low sulfur and low aromatic fuel meeting California standards for motor vehicle Diesel fuel; and
- Use of low-emitting Diesel engines meeting federal emissions standards for construction equipment if available.

The following mitigation measures are proposed to control fugitive dust emissions during construction of the project:

- Use either water application or chemical dust suppressant application to control dust emissions from unpaved surface travel and unpaved parking areas;
- Use vacuum sweeping and/or water flushing of paved road surface to remove buildup of loose material to control dust emissions from travel on the paved access road (including adjacent public streets impacted by construction activities) and paved parking areas;
- Cover all trucks hauling soil, sand, and other loose materials, or require all trucks to maintain at least two feet of freeboard;
- Limit traffic speeds on unpaved surfaces to 25 mph;
- Install sandbags or other erosion control measures to prevent silt runoff to roadways;
- Re-plant vegetation in disturbed areas as quickly as possible;
- As needed, use gravel pads along with wheel washers or wash tires of all trucks exiting construction site that carry track-out dirt from unpaved surfaces; and
- Mitigate fugitive dust emissions from wind erosion of areas disturbed from construction activities (including storage piles) by application of either water or chemical dust suppressant and/or use of wind breaks.

8.1D.4 Estimation of Emissions with Mitigation Measures

8.1D.4.1 Onsite Construction

Tables 8.1D-1 through 8.1D-3 show the estimated maximum daily and annual heavy equipment exhaust and fugitive dust emissions with recommended mitigation measures for onsite construction activities. Detailed emission calculations are included as Attachment 8.1D-1.

8.1D.4.2 Pipeline/Transmission Line Construction

Table 8.1D-4 shows the estimated maximum daily heavy equipment exhaust and fugitive dust emissions with recommended mitigation measures for the natural gas pipeline, water pipeline, and transmission line interconnect construction activities. The following is the expected construction period for each pipeline/transmission line route:

- Natural gas pipeline – 12 months
- Water pipeline – 12 months

- Transmission line interconnect – 1 month

Because of the temporary nature of these construction activities, annual emissions are not shown in the following emission summary tables for these construction activities. Detailed emission calculations are included as Attachment 8.1D-1.

Table 8.1D-1
Maximum Daily Emissions During Onsite Construction
(Month 7; Maximum Dust Emissions), Pounds Per Day

	NO_x	CO	POC	SO_x	PM_{10}
Onsite					
Construction Equipment	154.7	39.5	11.0	4.4	10.0
Fugitive Dust	--	--	--	--	54.9
Offsite					
Worker Travel, Truck/Rail Deliveries	98.9	738.4	60.5	1/7	3.5
Total Emissions					
Total	253.7	777.9	71.5	6.1	68.4

Table 8.1D-2
Maximum Daily Emissions During Onsite Construction
(Month 16; Maximum Exhaust Emissions), Pounds Per Day

	NO_x	CO	VOC	SO_x	PM_{10}
Onsite					
Construction Equipment	201.0	60.6	16.6	5.6	15.0
Fugitive Dust	--	--	--	--	19.5
Offsite					
Worker Travel, Truck/Rail Deliveries	114.8	739.9	61.1	2.7	3.9
Total Emissions					
Total	315.8	800.6	77.7	8.3	38.3

Table 8.1D-3
Annual Emissions During Onsite Construction, Tons Per Year

	NO_x	CO	VOC	SO_x	PM_{10}
Onsite					
Construction Equipment	18.1	6.6	1.7	0.5	1.5
Fugitive Dust	--	--	--	--	5.3
Offsite					
Worker Travel, Truck/Rail Deliveries	6.5	48.8	4.0	0.1	0.2
Total Emissions					
Total	24.6	55.4	5.7	0.6	7.0

Table 8.1D-4
Maximum Daily Emissions During Pipeline/Transmission Line Interconnect Construction
Pounds Per Day

	NO_x	CO	VOC	SO_x	PM_{10}
Natural Gas Pipeline					
Onsite					
Construction Equipment	44.6	14.3	3.3	1.5	2.2
Fugitive Dust	--	--	--	--	4.2
Offsite					
Truck Deliveries and Worker Travel	18.6	11.6	1.7	0.8	1.0
Total Emissions	63.2	25.9	5.0	2.3	7.4
Water Pipeline					
Onsite					
Construction Equipment	49.6	18.1	3.9	1.8	2.5
Fugitive Dust	--	--	--	--	5.4
Offsite					
Truck Deliveries and Worker Travel	27.8	17.4	2.5	1.2	1.6
Total Emissions	77.4	35.5	6.4	3.0	9.5
Transmission Line Interconnect					
Onsite					
Construction Equipment	60.9	12.5	3.9	1.8	2.8
Fugitive Dust	--	--	--	--	1.1
Offsite					
Truck Deliveries and Worker Travel	46.4	29.0	4.2	1.9	2.6
Total Emissions	107.3	41.5	8.1	3.7	6.5

8.1D.5 Analysis of Ambient Impacts from Onsite Construction

Ambient air quality impacts from emissions during construction of the Project were estimated using an air quality dispersion modeling analysis. The modeling analysis considers the construction site location, the surrounding topography, and the sources of emissions during construction, including vehicle and equipment exhaust emissions and fugitive dust.

8.1D.5.1 Existing Ambient Levels

The existing air quality in the project area is based on the same data used for the modeling analysis performed for the project operating impacts (see Section 8.1.5.1.2). Table 8.1D-4 shows the maximum concentrations of NO_x, SO_2, CO, and PM_{10} recorded in the project area over the past few years.

TABLE 8.1D-4

Maximum Background Concentrations, 1997-2000 (μg/m³)

Pollutant	Averaging Time	1997	1998	1999	2000
Fresno					
NO_2	1-Hour	173.0	210.6	193.6	176.7
	Annual	39.6	37.7	43.4	37.7
Fresno/Bakersfield					
SO_2	1-Hour	26	n/a	28.6	49.4
	3-Hour	13	n/a	23.4	44.2
	24-Hour	7.9	n/a	15.8	23.6
	Annual	0	n/a	8.0	5.3
Fresno					
CO	1-Hour	15,000	11,250	11,250	10,000
	8-Hour	6,322	6,533	6,144	5,822
PM_{10}	24-Hour	124	141	154	138
	Annual (AGM)[a]	37.1	27.1	35.8	29.5
	Annual (AAM)[b]	42.6	33.7	44.6	34.8

[a] Annual Geometric Mean

[b] Annual Arithmentic Mean

8.1D.5.2 Dispersion Model

As in the analysis of project operating impacts, the EPA-approved Industrial Source Complex Short Term (ISCST3) model was used to estimate ambient impacts from construction activities. A detailed discussion of the ISCST3 dispersion model is included in Section 8.1.5.1.2.

The emission sources for the construction site were grouped into two categories: exhaust emissions and dust emissions. The SCREEN3 model was used with typical Diesel exhaust characteristics to model final plume rise under worst-case meteorological conditions. Using this approach, the lowest final plume rise (which limits dispersion and leads to the highest ground-level concentrations) was determined to be 23.11 meters, and this elevation was used as the release height for all exhaust emissions in this modeling analysis. For construction dust emissions, an effective plume height of 0.5 meters was used in the modeling analysis. The exhaust and dust emissions were modeled as a single area source that covered the total area of the construction site. The construction impacts modeling analysis used the same receptor locations as used for the project operating impact analysis. A detailed discussion of the receptor locations is included in Section 8.1.5.1.2.

To determine the construction impacts on short-term ambient standards (24 hours and less), the worst-case daily onsite construction emission levels shown in Tables 8.1D-1 and 2 were used. For pollutants with annual average ambient standards, the annual onsite emission levels shown in Table 8.1D-3 were used. The same meteorological data set used for the project operating modeling analysis was used for the construction emission impacts analysis.

8.1D.5.3 Modeling Results

Based on the emission rates of NO_x, SO_2, CO, and PM_{10} and the meteorological data, the ISCST3 model calculates hourly and annual ambient impacts for each pollutant. As mentioned above, the modeled 1-hour, 3-hour, 8-hour, and 24-hour ambient impacts are based on the worst-case daily emission rates of NO_x, SO_2, CO, and PM_{10}. The annual impacts are based on the annual emission rates of these pollutants.

The one-hour and annual average concentrations of NO_2 were computed following the revised EPA guidance for computing these concentrations (August 9, 1995 *Federal Register,* 60 FR 40465). The OLM_ISC model was used for the one-hour average NO_2 impacts. The annual average was calculated using the ambient ratio method (ARM) with the EPA default value of 0.75 for the annual average NO_2/NO_x ratio.

The modeling analysis results are shown in Table 8.1D-6. Also included in the table are the maximum background levels that have occurred during the past few years and the resulting total ambient impacts. As shown in Table 8.1D-6, construction impacts alone for all modeled pollutants are expected to be below the most stringent state and national standards. With the exception of 24-hour and annual PM_{10} impacts, construction activities are not expected to cause the violation of any state or federal ambient air quality standard. However, the state 24-hour and annual average PM_{10} standards are exceeded in the absence of the construction emissions for the Project.

Table 8.1D-6

Modeled Maximum Construction Impacts

Pollutant	Averaging Time	Maximum Construction Impacts (μg/m^3)	Background (μg/m^3)	Total Impact (μg/m^3)	State Standard (μg/m^3)	Federal Standard (μg/m^3)
NO_2[a]	1-Hour	216.1	210.6	226.7	470	--
	Annual	36.7	43.4	80.1	--	100
SO_2	1-Hour	38.5	49.4	87.9	650	--
	3-Hour	21.7	44.2	65.9	--	1300
	24-Hour	7.3	23.6	30.9	109	365
	Annual	1.4	8.0	9.4	--	80
CO	1-Hour	415.0	15,000	15,415	23,000	40,000
	8-Hour	150.5	6,533	6,684	10,000	10,000
PM_{10}	24-Hour	118.4	154	272.4	50	150
	Annual[b]	25.7	37.1	62.8	30	--
	Annual[c]	25.7	44.6	70.3	--	50

Notes:
a. OLM_ISC used for 1-hr average impact and ARM applied for annual average, using EPA default ratio of 0.75.
b. Annual Geometric Mean.
c. Annual Arithmetic Mean.

It is important to note that over 80% (98.7 out of 118.4 ug/m3) of the maximum modeled 24-hour PM_{10} concentrations from construction activities are due to fugitive dust from construction activities rather than to exhaust from construction equipment. The impact from construction exhaust is only about 20 ug/m^3 on a 24-hour average basis. On an annual average basis, the exhaust contribution is about 15% of the total PM_{10} impact. Therefore, additional controls on construction equipment engines would be only marginally effective in minimizing PM_{10} impacts during construction. The emphasis should be on control of fugitive dust, and the dust mitigation measures already proposed by the applicant are expected to be very effective in minimizing fugitive dust emissions.

The ISCST3 model over-predicts PM_{10} construction emission impacts because of the cold plume (i.e., ambient temperature) effect of dust emissions. Most of the plume dispersion characteristics in the ISCST3 model are derived from observations of hot plumes associated with typical smokestacks. The ISCST3 model does compensate for plume temperature; however, for ambient temperature plumes, the model assumes negligible buoyancy and dispersion. Consequently, the ambient concentrations in cold plumes remain high even at significant distances from a source. The Project construction site impacts are not unusual in comparison to most construction sites; construction sites that use good dust suppression techniques and low-emitting vehicles typically do not cause violations of air quality standards. The input and output modeling files are being provided electronically.

8.1D.5.4 Health Risk of Diesel Exhaust

The combustion portion of annual PM_{10} emissions from Table 8.1D-3 above were modeled separately to determine the annual average Diesel PM_{10} exhaust concentration. This was used with the ARB-approved unit risk value of 300 in one million for a 70-year lifetime to determine the potential carcinogenic risk from Diesel exhaust during construction. The exposure was also adjusted by a factor of 2/70, or 0.0286, to correct for the 24-month exposure during the construction period.

The maximum modeled annual average concentration of Diesel exhaust PM_{10} is 4.05 ug/m^3. Using the unit risk value and adjustment factors described above, the carcinogenic risk due to exposure to Diesel exhaust during construction activities is expected to be approximately 35 in one million. This is above the 10 in one million level considered to be significant under the San Joaquin Valley APCD's CEQA guidelines.

This analysis is overly conservative for several reasons. First, as discussed above, the modeled PM_{10} concentrations from construction operations are overpredicted by the ISCST3 model. Second, this analysis assumes that all the combustion PM_{10} is emitted by Diesel engines, when in fact some of the engines will be gasoline-fueled and thus will not produce Diesel particulates.

8.1D.5.5 Analysis of Ambient Impacts from Pipeline/Transmission Line Interconnect Construction

Construction of the natural gas/wastewater pipelines and the transmission line interconnect activities will be of short duration, will require minimal equipment, and will generally occur along public roads and utility rights-of-way covering a large geographical area. Therefore, the potential ambient air quality impacts associated with these construction projects are expected to be minimal.

ATTACHMENT 8.1D-1

DETAILED CONSTRUCTION EMISSION CALCULATIONS

Construction Equipment Daily Exhaust Emissions (Month 7)
Central Valley Energy Center

Equipment	Number of Units	Hrs/Day Per Unit	Gals/Hr Per Unit	Total Fuel Use (Gals/day)	Emission Factors (lbs/1000 gals)(1) NOx	CO	POC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	POC	SOx	PM10
Crawler Crane- Greater than 300 ton														
Crawler Crane- Greater than 200 ton														
Crane - Mobile 65 ton														
Cranes -Mobile 45 ton														
Cranes - Mobile 35 ton														
Bulldozer D6H	1	8	5.50	44.00	270.01	39.13	15.65	7.10	15.65	11.88	1.72	0.69	0.31	0.69
Bulldozer D4C	1	8	3.00	24.00	270.01	39.13	15.65	7.10	15.65	6.48	0.94	0.38	0.17	0.38
Excavator- Trencher														
Excavator- Earth Scraper	3	8	9.00	216.00	270.01	39.13	15.65	7.10	15.65	58.32	8.45	3.38	1.53	3.38
Excavator-Motor Grader	1	8	5.00	40.00	270.01	39.13	15.65	7.10	15.65	10.80	1.57	0.63	0.28	0.63
Excavator- Backhoe/loader														
Excavator - loader	1	8	2.50	20.00	270.01	39.13	15.65	7.10	15.65	5.40	0.78	0.31	0.14	0.31
Vibratory Roller	1	8	10.00	80.00	270.01	39.13	15.65	7.10	15.65	21.60	3.13	1.25	0.57	1.25
Portable Compaction roller														
Truck- Water	1	8	3.13	25.04	170.68	106.79	15.33	7.10	9.59	4.27	2.67	0.38	0.18	0.24
Forklift	1	8	2.50	20.00	270.01	39.13	15.65	7.10	15.65	5.40	0.78	0.31	0.14	0.31
Dump Truck	2	8	3.13	50.08	170.68	106.79	15.33	7.10	9.59	8.55	5.35	0.77	0.36	0.48
Service Truck- 1 ton														
Truck- Fuel/Lube	1	8	3.13	25.04	170.68	106.79	15.33	7.10	9.59	4.27	2.67	0.38	0.18	0.24
Concrete Pumper Truck														
Tractor Truck 5th Wheel														
Trucks- Pickup 3/4 ton	2	8	0.78	12.48	74.40	59.47	5.57	7.10	4.83	0.93	0.74	0.07	0.09	0.06
Trucks- 3 ton	1	8	1.56	12.48	74.40	59.47	5.57	7.10	4.83	0.93	0.74	0.07	0.09	0.06
Diesel Powered Welder														
Light Plants	2	8	1.27	20.32	313.05	195.66	46.96	7.10	39.13	6.36	3.98	0.95	0.14	0.80
Portable Compaction- Vibratory Plate														
Portable Compaction- Vibratory Ram														
Articulating Boom Platforms														
Pumps														
Air Compressor 185 CFM	1	8	1.27	10.16	313.05	195.66	46.96	7.10	39.13	3.18	1.99	0.48	0.07	0.40
Air Compressor 750 CFM														
Concrete Vibrators														
Concrete Trowel Machine														
Fusion Welder														
Portable Power Generators	2	8	1.27	20.32	313.05	195.66	46.96	7.10	39.13	6.36	3.98	0.95	0.14	0.80
Total =										154.74	39.49	11.01	4.40	10.02

Notes:
(1) See notes for combustion emissions.

Construction Equipment Daily Exhaust Emissions (Month 16)
Central Valley Energy Center

Equipment	Number of Units	Hrs/Day Per Unit	Gals/Hr Per Unit	Total Fuel Use (Gals/day)	Emission Factors (lbs/1000 gals)(1) NOx	CO	POC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	POC	SOx	PM10
Crawler Crane- Greater than 300 ton	1	8	7.50	60.00	270.01	39.13	15.65	7.10	15.65	16.20	2.35	0.94	0.43	0.94
Crawler Crane- Greater than 200 ton	2	8	5.00	80.00	270.01	39.13	15.65	7.10	15.65	21.60	3.13	1.25	0.57	1.25
Crane - Mobile 65 ton	1	8	4.00	32.00	270.01	39.13	15.65	7.10	15.65	8.64	1.25	0.50	0.23	0.50
Cranes - Mobile 45 ton	1	8	4.00	32.00	270.01	39.13	15.65	7.10	15.65	8.64	1.25	0.50	0.23	0.50
Cranes - Mobile 35 ton	2	8	4.00	64.00	270.01	39.13	15.65	7.10	15.65	17.28	2.50	1.00	0.45	1.00
Bulldozer D6H														
Bulldozer D4C														
Excavator- Trencher	1	8	2.00	16.00	270.01	39.13	15.65	7.10	15.65	4.32	0.63	0.25	0.11	0.25
Excavator- Earth Scraper														
Excavator-Motor Grader														
Excavator- Backhoe/loader	1	8	2.50	20.00	270.01	39.13	15.65	7.10	15.65	5.40	0.78	0.31	0.14	0.31
Excavator - loader														
Vibratory Roller	1	8	10.00	80.00	270.01	39.13	15.65	7.10	15.65	21.60	3.13	1.25	0.57	1.25
Portable Compaction roller	1	8	10.00	80.00	270.01	39.13	15.65	7.10	15.65	21.60	3.13	1.25	0.57	1.25
Truck- Water	1	8	3.13	25.04	170.68	106.79	15.33	7.10	9.59	4.27	2.67	0.38	0.18	0.24
Forklift	1	8	2.50	20.00	270.01	39.13	15.65	7.10	15.65	5.40	0.78	0.31	0.14	0.31
Dump Truck														
Service Truck- 1 ton	1	8	1.56	12.48	74.40	59.47	5.57	7.10	4.83	0.93	0.74	0.07	0.09	0.06
Truck- Fuel/Lube	1	8	3.13	25.04	170.68	106.79	15.33	7.10	9.59	4.27	2.67	0.38	0.18	0.24
Concrete Pumper Truck														
Tractor Truck 5th Wheel	1	8	3.13	25.04	270.01	39.13	15.65	7.10	15.65	6.76	0.98	0.39	0.18	0.39
Trucks- Pickup 3/4 ton	6	8	0.78	37.44	74.40	59.47	5.57	7.10	4.83	2.79	2.23	0.21	0.27	0.18
Trucks- 3 ton	2	8	1.56	24.96	74.40	59.47	5.57	7.10	4.83	1.86	1.48	0.14	0.18	0.12
Diesel Powered Welder	2	8	1.27	20.32	313.05	195.66	46.96	7.10	39.13	6.36	3.98	0.95	0.14	0.80
Light Plants	2	8	1.27	20.32	313.05	195.66	46.96	7.10	39.13	6.36	3.98	0.95	0.14	0.80
Portable Compaction- Vibratory Plate	2	8	0.25	4.00	313.05	195.66	46.96	7.10	39.13	1.25	0.78	0.19	0.03	0.16
Portable Compaction- Vibratory Ram	2	8	0.25	4.00	313.05	195.66	46.96	7.10	39.13	1.25	0.78	0.19	0.03	0.16
Articulating Boom Platforms	6	8	0.25	12.00	313.05	195.66	46.96	7.10	39.13	3.76	2.35	0.56	0.09	0.47
Pumps	2	8	1.27	20.32	313.05	195.66	46.96	7.10	39.13	6.36	3.98	0.95	0.14	0.80
Air Compressor 185 CFM	1	8	1.27	10.16	313.05	195.66	46.96	7.10	39.13	3.18	1.99	0.48	0.07	0.40
Air Compressor 750 CFM	2	8	1.27	20.32	313.05	195.66	46.96	7.10	39.13	6.36	3.98	0.95	0.14	0.80
Concrete Vibrators	8	8	0.25	16.00	313.05	195.66	46.96	7.10	39.13	5.01	3.13	0.75	0.11	0.63
Concrete Trowel Machine	1	8	1.27	10.16	313.05	195.66	46.96	7.10	39.13	3.18	1.99	0.48	0.07	0.40
Fusion Welder	1	8	1.27	10.16	313.05	195.66	46.96	7.10	39.13	3.18	1.99	0.48	0.07	0.40
Portable Power Generators	1	8	1.27	10.16	313.05	195.66	46.96	7.10	39.13	3.18	1.99	0.48	0.07	0.40
Total =										201.00	60.62	16.57	5.62	14.99

Notes:
(1) See notes for combustion emissions.

Construction Equipment Annual Exhaust Emissions
Central Valley Energy Center

Equipment	Average Number of Units Per Year(1)	Average Operating Hrs/Day Per Unit	Gals/Hr Per Unit	Average Operating Days per Year	Total Fuel Use (Gals/yr)	Emission Factors (lbs/1000 gals)(2) NOx	CO	POC	SOx	PM10	Annual Emissions (tons/yr) NOx	CO	POC	SOx	PM10
Crawler Crane- Greater than 300 ton	0.27	8	7.5	250	4,090.91	270.01	39.13	15.65	7.10	15.65	0.55	0.08	0.03	0.01	0.03
Crawler Crane- Greater than 200 ton	1.18	8	5	250	11,818.18	270.01	39.13	15.65	7.10	15.65	1.60	0.23	0.09	0.04	0.09
Crane - Mobile 65 ton	0.91	8	4	250	7,272.73	270.01	39.13	15.65	7.10	15.65	0.98	0.14	0.06	0.03	0.06
Cranes -Mobile 45 ton	0.50	8	4	250	4,000.00	270.01	39.13	15.65	7.10	15.65	0.54	0.08	0.03	0.01	0.03
Cranes - Mobile 35 ton	0.95	8	4	250	7,636.36	270.01	39.13	15.65	7.10	15.65	1.03	0.15	0.06	0.03	0.06
Bulldozer D6H	0.14	8	5.5	250	1,500.00	270.01	39.13	15.65	7.10	15.65	0.20	0.03	0.01	0.01	0.01
Bulldozer D4C	0.18	8	3	250	1,090.91	270.01	39.13	15.65	7.10	15.65	0.15	0.02	0.01	0.00	0.01
Excavator- Trencher	0.27	8	2	250	1,090.91	270.01	39.13	15.65	7.10	15.65	0.15	0.02	0.01	0.00	0.01
Excavator- Earth Scraper	0.14	8	9	250	2,454.55	270.01	39.13	15.65	7.10	15.65	0.33	0.05	0.02	0.01	0.02
Excavator-Motor Grader	0.32	8	5	250	3,181.82	270.01	39.13	15.65	7.10	15.65	0.43	0.06	0.02	0.01	0.02
Excavator- Backhoe/loader	0.73	8	2.5	250	3,636.36	270.01	39.13	15.65	7.10	15.65	0.49	0.07	0.03	0.01	0.03
Excavator - loader	0.18	8	2.5	250	909.09	270.01	39.13	15.65	7.10	15.65	0.12	0.02	0.01	0.00	0.01
Vibratory Roller	0.36	8	10	250	7,272.73	270.01	39.13	15.65	7.10	15.65	0.98	0.14	0.06	0.03	0.06
Portable Compaction roller	0.36	8	10	250	7,272.73	270.01	39.13	15.65	7.10	15.65	0.98	0.14	0.06	0.03	0.06
Truck- Water	0.73	8	3.13	250	4,552.73	170.68	106.79	15.33	7.10	9.59	0.39	0.24	0.03	0.02	0.02
Forklift	1.00	8	2.5	250	5,000.00	270.01	39.13	15.65	7.10	15.65	0.68	0.10	0.04	0.02	0.04
Dump Truck	0.27	8	3.13	250	1,707.27	170.68	106.79	15.33	7.10	9.59	0.15	0.09	0.01	0.01	0.01
Service Truck- 1 ton	0.41	8	1.56	250	1,276.36	74.40	59.47	5.57	7.10	4.83	0.05	0.04	0.00	0.00	0.00
Truck- Fuel/Lube	0.77	8	3.13	250	4,837.27	170.68	106.79	15.33	7.10	9.59	0.41	0.26	0.04	0.02	0.02
Concrete Pumper Truck	0.23	8	3.13	250	1,422.73	170.68	106.79	15.33	7.10	9.59	0.12	0.08	0.01	0.01	0.01
Tractor Truck 5th Wheel	0.82	8	3.13	250	5,121.82	270.01	39.13	15.65	7.10	15.65	0.69	0.10	0.04	0.02	0.04
Trucks- Pickup 3/4 ton	3.73	8	0.78	250	5,814.55	74.40	59.47	5.57	7.10	4.83	0.22	0.17	0.02	0.02	0.01
Trucks- 3 ton	1.82	8	1.56	250	5,672.73	74.40	59.47	5.57	7.10	4.83	0.21	0.17	0.02	0.02	0.01
Diesel Powered Welder	5.45	8	1.27	250	13,854.55	313.05	195.66	46.96	7.10	39.13	2.17	1.36	0.33	0.05	0.27
Light Plants	1.55	8	1.27	250	3,925.45	313.05	195.66	46.96	7.10	39.13	0.61	0.38	0.09	0.01	0.08
Portable Compaction- Vibratory Plate	0.82	8	0.25	250	409.09	313.05	195.66	46.96	7.10	39.13	0.06	0.04	0.01	0.00	0.01
Portable Compaction- Vibratory Ram	1.18	8	0.25	250	590.91	313.05	195.66	46.96	7.10	39.13	0.09	0.06	0.01	0.00	0.01
Articulating Boom Platforms	1.00	8	0.25	250	500.00	313.05	195.66	46.96	7.10	39.13	0.08	0.05	0.01	0.00	0.01
Pumps	2.59	8	1.27	250	6,580.91	313.05	195.66	46.96	7.10	39.13	1.03	0.64	0.15	0.02	0.13
Air Compressor 185 CFM	2.05	8	1.27	250	5,195.45	313.05	195.66	46.96	7.10	39.13	0.81	0.51	0.12	0.02	0.10
Air Compressor 750 CFM	0.95	8	1.27	250	2,424.55	313.05	195.66	46.96	7.10	39.13	0.38	0.24	0.06	0.01	0.05
Concrete Vibrators	1.38	8	0.25	250	690.48	313.05	195.66	46.96	7.10	39.13	0.11	0.07	0.02	0.00	0.01
Concrete Trowel Machine	2.64	8	1.27	250	6,696.36	313.05	195.66	46.96	7.10	39.13	1.05	0.66	0.16	0.02	0.13
Fusion Welder	0.27	8	1.27	250	692.73	313.05	195.66	46.96	7.10	39.13	0.11	0.07	0.02	0.00	0.01
Portable Power Generators	0.29	8	1.27	250	725.71	313.05	195.66	46.96	7.10	39.13	0.11	0.07	0.02	0.00	0.01
Total =											18.06	6.62	1.70	0.50	1.49

Notes:
(1) Based on average number of units operating over the construction period.
(2) See notes on combustion emissions.

Delivery Truck Daily Emissions (Month 7) Central Valley Energy Center													
Number of Deliveries Per Day(1)	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1)					Daily Emissions (lbs/day)					
			NOx	CO	POC	SOx	PM10	NOx	CO	POC	SOx	PM10
20	70	1400	0.0280	0.0175	0.0025	0.0012	0.0016	39.23	24.54	3.52	1.62	2.20
Idle exhaust (2)												0.084

Notes:
(1) See notes for combustion emissions.
(2) 10 trucks per day times 1 hr idle time per visit times 0.0042 lb/hr.

Delivery Truck Daily Emissions (Month 16) Central Valley Energy Center												
Number of Deliveries Per Day(1)	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1)					Daily Emissions (lbs/day)				
			NOx	CO	POC	SOx	PM10	NOx	CO	POC	SOx	PM10
20	70	1400	0.0280	0.0175	0.0025	0.0012	0.0016	39.23	24.54	3.52	1.62	2.20
Idle exhaust (2)												0.084

Notes:
(1) See notes for combustion emissions.
(2) 52 trucks per day times 1 hr idle time per visit times 0.0042 lb/hr.

Delivery Truck Annual Emissions Central Valley Energy Center												
Average Number of Deliveries Per Year	Average Round Trip Haul Distance (miles)	Vehicle Miles Traveled Per Year	Emission Factors (lbs/vmt)(1)					Annual Emissions (tons/yr)				
			NOx	CO	POC	SOx	PM10	NOx	CO	POC	SOx	PM10
2225.50	70	155785.00	0.0280	0.0175	0.0025	0.0012	0.0016	2.18	1.37	0.20	0.09	0.12
Idle exhaust (2,3)												0.00467

Notes:
(1) See notes for combustion emissions.
(2) 2427.82 trucks per year times 1 hr idle time per visit times 0.0042 lb/hr
(3) Based on 1.91 g/hr idle emission rate for the composite HDD truck fleet in 2001 from EPA's PART5 model.

Daily Fugitive Dust Emissions (Month 7)
Central Valley Energy Center

Equipment	Number of Units	Daily Process Rate Per Unit	Total Process Rate	Units	PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	PM10 Emissions (lbs/day)
Bulldozer D6H	1	8.0	8.0	hours	0.7528		6.02
Bulldozer D4C	1	8.0	8.0	hours	0.7528		6.02
Excavator- Trencher Excavation							
Excavator- Earth Scraper Excavation	3	8.0	24.0	hours	0.7528		18.07
Excavator- Earth Scraper Unpaved Road Travel	3	14.5	43.6	vmt	0.2656	69%	3.54
Excavator-Motor Grader	1	24.0	24.0	vmt	0.2754		6.61
Excavator- Backhoe Excavation							
Excavator - Loader Excavation	1	3,250.0	3,250.0	tons	0.0004		1.38
Excavator - Loader Unpaved Road Travel	1	28.4	28.4	vmt	0.1148	69%	1.00
Water Truck Unpaved Road Travel	1	20.0	20.0	vmt	0.1522	69%	0.93
Forklift Unpaved Road Travel	1	16.0	16.0	vmt	0.0970	69%	0.47
Dump Truck Unpaved Road Travel	2	13.6	27.3	vmt	0.1589	69%	1.32
Dump Truck Unloading	2	1,625.0	3,250.0	tons	0.0004		1.38
Service Truck Unpaved Road Travel							
Fuel/Lube Truck Unpaved Road Travel	1	3.4	3.4	vmt	0.1181	69%	0.12
Concrete Pumper Truck Unpaved Road Travel							
Tractor Truck 5th Wheel Unpaved Road Travel							
Pickup Truck Unpaved Road Travel	2	17.0	34.1	vmt	0.0599	69%	0.62
3 ton Truck Unpaved Road Travel	1	8.5	8.5	vmt	0.0803	69%	0.21
Windblown Dust (active construction area)	N/A	871,200.0	871,200.0	sq.ft.	2.523E-05	69%	6.72
Worker Paved Road Travel	386	0.5	190.1	vmt	0.0005		0.09
Delivery Truck Paved Road Travel	20	0.5	9.8	vmt	0.0185		0.18
Delivery Truck Unpaved Road Travel	20	0.2	3.4	vmt	0.1589	69%	0.17
Total =							54.86

Notes:
(1) See notes for fugitive dust emission calculations.

Annual Fugitive Dust Emissions
Central Valley Energy Center

Activity	Average Daily PM10 Emissions(1) (lbs/day)	Days per Year	Annual PM10 Emissions (tons/yr)
Construction Activities	32.54	250	4.07
Windblown Dust	6.72	365	1.23
Total =			5.29

Notes:
(1) Based on average of daily emissions during Months 7, 9, 15, and 16.

Natural Gas Pipeline Construction Heavy Equipment Daily Emissions

	Equipment		Load	Number	Hrs/Day			Emission Factors (1)						Daily Emissions (lbs/day)		
Equipment	Rating	Units	Factor(1)	of Units	Per Unit	NOx	CO	VOC	SOx	PM10	Units	NOx	CO	VOC	SOx	PM10
Trencher	150	bhp	0.38	1	8	6.90	1.00	0.40	0.18	0.3	gm/bhp-hr	6.94	1.01	0.40	0.18	0.30
Backhoe	100	bhp	0.38	1	8	6.90	1.00	0.40	0.18	0.3	gm/bhp-hr	4.62	0.67	0.27	0.12	0.20
Compactor	100	bhp	0.59	1	8	6.90	1.00	0.40	0.18	0.3	gm/bhp-hr	7.18	1.04	0.42	0.19	0.31
Paving machine	100	bhp	0.56	1	8	6.90	1.00	0.40	0.18	0.3	gm/bhp-hr	6.81	0.99	0.40	0.18	0.30
Grader	100	bhp	0.54	1	8	6.90	1.00	0.40	0.18	0.3	gm/bhp-hr	6.57	0.95	0.38	0.17	0.29
Water Truck	150	bhp	0.65	1	8	3.36	2.60	0.39	0.18	0.22	gm/bhp-hr	5.78	4.47	0.67	0.31	0.38
Fuel/lube truck	175	bhp	0.65	1	8	3.36	2.60	0.39	0.18	0.22	gm/bhp-hr	6.74	5.22	0.78	0.36	0.44
Total =												44.65	14.34	3.32	1.52	2.22

Notes:
(1) See notes for combustion emissions.

Water Pipeline Construction Heavy Equipment Daily Emissions

	Equipment		Load	Number	Hrs/Day			Emission Factors (1)						Daily Emissions (lbs/day)		
Equipment	Rating	Units	Factor(1)	of Units	Per Unit	NOx	CO	VOC	SOx	PM10	Units	NOx	CO	VOC	SOx	PM10
Trencher	150	bhp	0.38	1	8	6.90	1.00	0.40	0.18	0.30	gm/bhp-hr	6.94	1.01	0.40	0.18	0.30
Backhoe	100	bhp	0.38	1	8	6.90	1.00	0.40	0.18	0.30	gm/bhp-hr	4.62	0.67	0.27	0.12	0.20
Compactor	100	bhp	0.59	1	8	6.90	1.00	0.40	0.18	0.30	gm/bhp-hr	7.18	1.04	0.42	0.19	0.31
Loader	150	bhp	0.38	1	8	6.90	1.00	0.40	0.18	0.30	gm/bhp-hr	6.94	1.01	0.40	0.18	0.30
Grader	100	bhp	0.54	1	8	6.90	1.00	0.40	0.18	0.30	gm/bhp-hr	6.57	0.95	0.38	0.17	0.29
Water Truck	150	bhp	0.65	1	8	3.36	2.60	0.39	0.18	0.22	gm/bhp-hr	5.78	4.47	0.67	0.31	0.38
Dump Truck	300	bhp	0.65	1	8	3.36	2.60	0.39	0.18	0.22	gm/bhp-hr	11.56	8.94	1.34	0.62	0.76
Total =												49.58	18.09	3.88	1.78	2.54

Notes:
(1) See notes for combustion emissions.

Transmission Line Interconnect Construction Heavy Equipment Daily Emissions

	Equipment		Load	Number	Hrs/Day			Emission Factors (1)						Daily Emissions (lbs/day)		
Equipment	Rating	Units	Factor(1)	of Units	Per Unit	NOx	CO	VOC	SOx	PM10	Units	NOx	CO	VOC	SOx	PM10
Auger	150	bhp	0.75	1	8	6.90	1.00	0.40	0.18	0.30	gm/bhp-hr	13.69	1.98	0.79	0.36	0.60
Backhoe	100	bhp	0.38	1	8	6.90	1.00	0.40	0.18	0.30	gm/bhp-hr	4.62	0.67	0.27	0.12	0.20
Crane	250	bhp	0.43	1	8	6.90	1.00	0.40	0.18	0.30	gm/bhp-hr	13.08	1.90	0.76	0.34	0.57
Crawler Tractor	300	bhp	0.57	1	8	6.90	1.00	0.40	0.18	0.30	gm/bhp-hr	20.81	3.02	1.21	0.55	0.90
Water Truck	150	bhp	0.65	1	8	3.36	2.60	0.39	0.18	0.22	gm/bhp-hr	5.78	4.47	0.67	0.31	0.38
Air Compressor	50	bhp	0.48	1	8	6.90	1.00	0.40	0.18	0.30	gm/bhp-hr	2.92	0.42	0.17	0.08	0.13
Total =												60.90	12.46	3.87	1.76	2.78

Notes:
(1) See notes for combustion emissions.

Natural Gas Pipeline Construction Delivery Truck Daily Emissions

Number of Deliveries Per Day	Avg Round Trip Haul Distance (mi)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1) NOx	CO	VOC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
4	165.6	662.4	0.0280	0.0175	0.0025	0.0012	0.0016	18.56	11.61	1.67	0.77	1.04

Notes:
(1) See notes for combustion emissions.

Water Pipeline Construction Delivery Truck Daily Emissions

Number of Deliveries Per Day	Avg Round Trip Haul Distance (mi)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1) NOx	CO	VOC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
6	165.6	993.6	0.0280	0.0175	0.0025	0.0012	0.0016	27.84	17.42	2.50	1.15	1.56

Notes:
(1) See notes for combustion emissions.

Transmission Line Interconnect Construction Delivery Truck Daily Emissions

Number of Deliveries Per Day	Avg Round Trip Haul Distance (mi)	Vehicle Miles Traveled Per Day	Emission Factors (lbs/vmt)(1) NOx	CO	VOC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	VOC	SOx	PM10
10	165.6	1656	0.0280	0.0175	0.0025	0.0012	0.0016	46.40	29.03	4.17	1.92	2.61

Notes:
(1) See notes for combustion emissions.

Natural Gas Pipeline Construction Daily Fugitive Dust Emissions

Operation	Daily Process Rate Per Unit	Units	PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	PM10 Emissions (lbs/day)
Windblown Dust	2000	sq.ft./day	2.5229E-05	88%	0.01
Excavation	667	cu.yd./day	0.0018	0%	1.20
Back filling	700	tons/day	0.0001	0%	0.07
Grader Operation	10	vmt	0.2754	0%	2.75
Water truck unpaved surface travel	10	vmt	0.1522	88%	0.18
Delivery truck unpaved surface travel	2	vmt	0.1589	88%	0.04
Total =					4.24

Notes:
(1) See notes for fugitive dust emission calculations.

Water Pipeline Construction Daily Fugitive Dust Emissions

Operation	Daily Process Rate Per Unit	Units	PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	PM10 Emissions (lbs/day)
Windblown Dust	3000	sq.ft./day	2.5229E-05	66%	0.03
Excavation	1500	cu.yd./day	0.0018	0%	2.70
Back filling	900	tons/day	0.0001	0%	0.09
Grader Operation	8	vmt	0.2754	0%	2.20
Water truck unpaved surface travel	6	vmt	0.1522	66%	0.31
Delivery truck unpaved surface travel	1	vmt	0.1589	66%	0.06
Total =					5.39

Notes:
(1) See notes for fugitive dust emission calculations.

Transmission Line Interconnect Construction Daily Fugitive Dust Emissions

Operation	Daily Process Rate Per Unit	Units	PM10 Emission Factor(1) (lbs/unit)	Control Factor(1) (%)	PM10 Emissions (lbs/day)
Windblown Dust	1000	sq.ft./day	2.5229E-05	66%	0.01
Excavation	500	cu.yd./day	0.0018	0%	0.90
Back filling	250	tons/day	0.0001	0%	0.03
Water truck unpaved surface travel	2	vmt	0.1522	66%	0.10
Delivery truck unpaved surface travel	2	vmt	0.1589	66%	0.10
Total =					1.14

Notes:
(1) See notes for fugitive dust emission calculations.

Worker Travel Daily Emissions (Month 7)
Central Valley Energy Center

Number of Workers Per Day(1)	Average Vehicle Occupancy (person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Vehicle Miles Traveled Per Day (Miles)	Emission Factors (lbs/vmt)(1) NOx	CO	POC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	POC	SOx	PM10
386	1.3	297	70	20785	0.0029	0.0343	0.0027	0.0000	0.0001	59.71	713.83	57.00	0.04	1.21

Notes:
(1) See notes for combustion emissions.

Worker Travel Daily Emissions (Month 16)
Central Valley Energy Center

Number of Workers Per Day(1)	Average Vehicle Occupancy (person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Vehicle Miles Traveled Per Day (Miles)	Emission Factors (lbs/vmt)(1) NOx	CO	POC	SOx	PM10	Daily Emissions (lbs/day) NOx	CO	POC	SOx	PM10
386	1.3	297	70	20785	0.0029	0.0343	0.0027	0.0000	0.0001	59.71	713.83	57.00	0.04	1.21

Notes:
(1) See notes for combustion emissions.

Worker Travel Annual Emissions
Central Valley Energy Center

Average Number of Workers Per Day	Average Vehicle Occupancy (person/veh.)	Number of Round Trips Per Day	Average Round Trip Haul Distance (Miles)	Days per Year	Vehicle Miles Traveled Per Year	Emission Factors (lbs/vmt)(1) NOx	CO	POC	SOx	PM10	Annual Emissions (tons/yr) NOx	CO	POC	SOx	PM10
205	1.3	158	70	250	2,759,615	0.0029	0.0343	0.0027	0.0000	0.0001	3.96	47.39	3.78	0.00	0.08

Notes:
(1) See notes for combustion emissions.

Notes:
(1) From Section 8.10.2.2 of AFC.

Notes - Fugitive Dust Emission Calculations

(1) Paved road travel emission factors for delivery trucks and worker automobiles are based on AP-42, Section 13.2.1, 10/97.
(2) Wind erosion emission factor for active construction area is based on "Improvement of Specific Emission Factors (BACM Project No. 1), Final Report", prepared for South Coast AQMD by Midwest Research Institute, March 1996.
(3) Finish grading emission factor is based on AP-42, Table 11.9-2, 1/95.
(4) Bulldozer and scraper excavation emission factors are based AP-42, Table 11.9.2, 1/95.
(5) Material unloading emission factors are based on AP-42, p. 13.2.4-3, 1/95.
(6) Loader unpaved road travel emission factor is based on AP-42, Section 13.2.2, 1/95.
(7) Backhoe trenching emission factor is based on AP-42, Table 11.9-2 (dragline operations), 1/95.
(8) Unpaved road travel emission factors for water trucks, fuel trucks, service trucks, dump trucks, scrapers, forklifts, pickup trucks, delivery trucks, 5th wheel tractor trucks, and concrete trucks are based on AP-42, Section 13.2.2, 9/98.
(9) Dust control efficiency for unpaved road travel and active excavation area is based on "Control of Open Fugitive Dust Sources", U.S. EPA, 9/88.

Notes - Combustion Emission Calculations

(1) For Construction Equipment
For heavy Diesel construction equipment, emission factors based on equipment meeting EPA 1996 off-road Diesel standards and use of CARB low-sulfur fuel.
For trucks, depending on size of truck, emissions factors based on MVE17G version 1.0c for heavy-heavy duty or medium duty Diesel trucks, fleet average for calendar year 2000.
For portable equipment, emission factors based on EPA's "Non-road Engine and Vehicle Emission Study Report", 11/91, Table 2-07, for generator sets, welders, pumps, and air compressors less than 50 hp

(2) For Delivery Trucks
From MVE17G version 1.0c, heavy-heavy duty Diesel trucks, fleet average for calendar year 2000.

(3) For Worker Travel
From MVE17G version 1.0c, average of light duty automobiles and light duty trucks, fleet average for calendar year 2000.

APPENDIX 8.1E

Construction Emissions and Impact Analysis

Appendix 8.1E

Evaluation Of Best Available Control Technology

To evaluate BACT for the proposed turbines, the SJVUAPCD BACT guideline for large gas turbines (heat input rating greater than 374 MMBtu/hr) was reviewed. The relevant BACT determinations for this analysis are shown in Table 8.1E-1.

Table 8.1E-1

SJVUAPCD BACT Guideline For Large Gas Turbines

Pollutant	Achieved in Practice or Contained in SIP	Technologically Feasible
Nitrogen Oxides	2.5 ppmvd, 1 hr avg, excluding startup and shutdown. SCR or equal and natural gas fuel.	2.5 ppmvd, 1 hr avg, excluding startup and shutdown. SCR or equal and natural gas fuel.
Sulfur Dioxide	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more than 0.75 g S/100 dscf.	1. PUC-regulated natural gas or 2. Non-PUC-regulated gas with no more than 0.75 g S/100 dscf 3. LPG
Carbon Monoxide	6.0 ppmv Oxidation catalyst and natural gas fuel	4.0 ppmv Oxidation catalyst and natural gas fuel or LPG
VOC	2.0 ppmv and natural gas fuel	2.0 ppmv and natural gas fuel
PM_{10}	Air inlet filter cooler, lube oil vent coalescer and natural gas fuel	Air inlet cooler/filter, lube oil vent coalescer and natural gas fuel or LPG

The EPA RACT-BACT-LAER Clearinghouse (RBLC) was also consulted to review recent EPA BACT decisions for gas-fired gas turbines. These recent BACT decisions are summarized in Table 8.1E-2 below. NOx levels shown in these BACT determinations are very high, although EPA has recently stated that the SCONOx technology has demonstrated that 2.5 ppm is achievable in practice. CO levels in this listing are also relatively high, and do not indicate that oxidation catalysts have been considered BACT for CO or VOCs.

The ARB's BACT Clearinghouse Database was also reviewed for recent BACT decisions regarding large gas turbine projects in California. Relevant BACT decisions are summarized in Table 8.1E-3. NOx levels shown in these determinations range from 5 to 2.5 ppm.

Finally, the ARB's Guidance for Power Plant Sitting and Best Available Control Technology was also reviewed. The relevant BACT levels recommended in the ARB power plant guidance document are summarized in Table 8.1E-4.

The Project proposes to use dry low-NOx combustors with selective catalytic reduction technology that will achieve a NOx exhaust concentration of 2.5 ppmv or less (1-hr average), 2.0 ppmv (annual average), and a CO exhaust concentration of 6 ppmv. The gas turbines will be fueled with natural gas to minimize SO_2 and PM_{10} emissions. VOC levels are inherently very low for the turbines (i.e., 2 ppmv) and no further reductions are needed to comply with BACT. The control systems will also achieve an ammonia slip of 10 ppmv (1-hour average). These pollutant levels will achieve emission reductions consistent with the SJBUAPCD BACT guideline and the ARB BACT guideline for power plants. A more detailed top down analysis for BACT for NOx and ammonia emissions is included as Attachment 8.1E-1.

TABLE 8.1E-2

GAS TURBINE BACT DETERMINATIONS FOR EPA RBLC CLEARINGHOUSE

FACILITY/LOCATION	DATE PERMIT ISSUED	EQUIPMENT/RATING	NOX LIMIT/CONTROL TECHNOLOGY	CO LIMIT/CONTROL TECHNOLOGY
Alabama Power Company McIntosh, AL	7/10/97	100 MW combustion turbine w/ duct burner	15 ppm (dry low-NOx burners)	n/a
Lordsburg L.P. Lordsburg, NM	6/18/97	100 MW combustion turbine	15 ppm (dry low-NOx technology)	50 ppm (dry low-NOx technology)
Mead Coated Board, Inc. Phenix City, AL	3/12/97	25 MW combustion turbine w/ fired HRSG	25 ppm (dry low-NOx combustor)	28 ppm (proper design and good combustion practices)
Northern California Power Agency Lodi, CA	10/02/97	GE Frame 5 gas turbine	25 ppm	n/a
Portside Energy Corp. Portage, IN	5/13/96	63 MW gas turbine w/ unfired HRSG	n/a	10 ppm (good combustion)
Southwestern Public Service Hobbs, NM	2/15/97	Gas turbine	15 ppm w/o power augmentation 25 ppm w/ augmentation	good combustion practices

TABLE 8.1E-3
SUMMARY OF BACT DETERMINATIONS FROM ARB BACT CLEARINGHOUSE

FACILITY/DISTRICT	PERMIT NO.	EQUIPMENT/RATING	NOX LIMIT/CONTROL TECHNOLOGY	VOC/HC LIMIT/CONTROL TECHNOLOGY
Sacramento Cogeneration Authority Sacramento Metropolitan AQMD	A330-849-98 A330-850-98 A330-851-98	GE LM6000 combined-cycle gas turbine w/ supplemental firing (42 MW each)	5 ppm (dry low-NOx combustion and SCR)	oxidation catalyst (10% destruction efficiency)
Sacramento Power Authority Sacramento Metropolitan AQMD	A330-852-98	Siemens V84.2 combined-cycle gas turbine w/ supplemental firing (103 MW)	3 ppm (water injection and SCR)	oxidation catalyst (5% destruction efficiency)
Carson Energy Sacramento Metropolitan AQMD	A330-854-98	GE LM6000 combined-cycle gas turbine w/ supplemental firing (42 MW)	5 ppm (water injection and SCR)	oxidation catalyst (10% destruction efficiency)
SEPCO	A330-855-98	GE Frame 7EA gas turbine w/ supplemental firing (82 MW)	5 ppm (dry low-NOx combustion and SCR)[1]	oxidation catalyst (5% destruction efficiency)
La Paloma Generating Company, LLC	S-3412-1	ABB Model GT-24 gas turbine w/o supplemental firing (262 MW each)	2.5 ppm (dry low-NOx combustion and SCR)	
Sutter Power Plant	A330-882-99	Westinghouse 501F gas turbine w/ supplemental firing (250MW each)	2.5 ppm (dry low-NOx combustion and SCR)	
Crockett Cogeneration	A330-859-98	GE Frame 7FA gas turbine w/ supplemental firing (240MW)	5 ppm (dry low-NOx combustion and SCR)	

Note: 1. District indicates that applicant proposed 2.6 ppm to lower offset liability.

TABLE 8.1E-4

ARB BACT GUIDANCE FOR POWER PLANTS

POLLUTANT	BACT
Nitrogen Oxides	2.5 ppmv @ 15% O2 (1-hour average) 2.0 ppmv @ 15% O2 (3-hour average)
Sulfur Dioxide	Fuel sulfur limit of 1.0 grains/100 scf
Carbon Monoxide	Nonattainment areas: 6 ppmv @ 15% O2 (3-hour average) Attainment areas: District discretion
VOC	2 ppmv @ 15% O2 (3-hour average)
NH_3	5 ppmv @ 15% O2 (3-hour average)
PM10	Fuel sulfur limit of 1.0 grains/100 scf

To evaluate BACT for the proposed auxiliary boiler, the SJVUAPCD BACT guideline for natural gas fired boilers was reviewed. The relevant BACT determinations for this analysis are shown in 8.1E-5.

TABLE 8.1E-5

SJVUAPCD BACT GUIDANCE FOR NATURAL GAS FIRED BOILERS

POLLUTANT	BACT
NOx	9 ppm @ 3% O2
SOx	Natural gas fuel with LPG backup
CO	Natural gas fuel with LPG backup
VOC	Natural gas fuel with LPG backup
PM10	Natural gas fuel with LPG backup

The auxiliary boiler will meet the BACT limits shown on Table 8.1E-5 with the use of low-NOx burners, natural gas fuel and proper combustion.

To evaluate BACT for the proposed fire pump engine, the SJVUAPCD BACT guideline for Diesel IC engines driving fire pumps was reviewed. The relevant BACT determinations for this analysis are shown in Table 8.1E-6.

TABLE 8.1E-6

SCAQMD BACT GUIDANCE FOR EMERGENCY DIESEL IC ENGINES

POLLUTANT	Emergency Diesel IC Engines	Diesel Engines Driving Fire Pumps
NOx	6.9 g/bhp-hr or less OR turbocharging and FITR	7.2 g/bhp-hr OR turbocharging and FITR
SOx	Low-sulfur Diesel fuel, or very low-sulfur Diesel fuel, where available	Low-sulfur Diesel fuel
CO	2.0 g/bhp-hr	Oxidation catalyst (technologicall feasible)
VOC	Positive crankcase ventilation	Oxidation catalyst (technologicall feasible)
PM10	0.1 g/bhp-hr (if TBACT is triggered) or 0.4 g/bhp-hr (if TBACT not triggered)	Low-sulfur Diesel fuel

The emergency Diesel fire pump engine will meet the BACT limits shown on Table 8.1E-6 with the use of low sulfur content fuel and low emission engine designs.

Attachment 8.1E-1

Top Down Analysis for BACT for NOx and Ammonia Emissions

BACT is defined in SJVUAPCD Rule 2201 as:

"…the most stringent emission limitation or control technique of the following:

1. Has been achieved in practice for such emissions unit or class of source; or
2. Is contained in any State Implementation Plan approved by the Environmental Protection Agency for such emissions unit category and class of source. A specific limitation or control technique shall not apply if the owner or operator of the proposed emissions unit demonstrates to the satisfaction of the APCO that such limitation or control technique is not presently achievable; or
3. Is any other emission limitation or control technique, including process and equipment changes of basic or control equipment, found by the APVO to be technologically feasible for such class or category of sources or for a specific source, and cost-effective as determined by the APCO."

Of these three "prongs" of the BACT definition, the first and third are generally controlling. This analysis will follow EPA's guidance for the preparation of "top down" BACT analyses focusing specifically on identifying emission limitations or control techniques that are achieved in practice and technically feasible.

A "top-down" analysis format, consistent with guidance provided in EPA's October 1990 Draft New Source Review Workshop Manual, has been used for the BACT analysis. That guidance lays out five steps for a top-down BACT analysis, as follows:

1. Identify all control technologies
2. Eliminate technically infeasible options
3. Rank remaining control technologies by control effectiveness
4. Evaluate most effective controls and document results
5. Select BACT

This procedure is followed for each of the two pollutants evaluated in this analysis.

1. <u>Control of Nitrogen Oxides</u>

a. Identify All Control Technologies

The maximum NOx emission rate for this analysis is considered to be 75 ppmvd @ 15% O_2, based on the governing new source performance standard (40 CFR 60 Subpart GG). This maximum emissions rate provides the frame of reference for the evaluation of control effectiveness and feasibility. The maximum degree of control, resulting in the minimum emission rate, is a combination of dry low-NOx combustors and either selective catalytic reduction or SCONOx to achieve a long term NOx limit of approximately 1 ppmvd. Intermediate levels of control are also evaluated.

There are three basic means of controlling NOx emissions from combustion turbines: wet combustion controls, dry combustion controls, and post-combustion controls. Wet and dry combustion controls act to reduce the formation of NOx during the combustion process, while post-combustion controls remove NOx from the exhaust stream. Potential NOx control technologies for combustion gas turbines include the following:

Wet combustion controls

- Water injection
- Steam injection

Dry combustion controls

- Dry low-NOx combustor design
- Catalytic combustors (e.g., XONON)
- Other combustion modifications

Post-combustion controls

- Selective non-catalytic reduction (SNCR)
- Non-selective catalytic reduction (NSCR)
- Selective catalytic reduction (SCR)
- SCONOx

b. Eliminate Technically Infeasible Options

The performance and technical feasibility of available NOx control technologies are discussed in more detail below.

Combustion Modifications

(i) Wet Combustion Controls

Steam or water injection directly into the turbine combustor is one of the most common NOx control techniques for combustion turbines. These wet injection techniques lower the flame temperature in the combustor and thereby reduce thermal NOx formation. The water or steam-to-fuel injection ratio is the most significant factor affecting the performance of wet controls. Steam injection techniques can reduce NOx emissions in gas-fired gas turbines to between 15 and 25 ppmv at 15% O_2; the practical limit of water injection has been demonstrated at approximately 25-42 ppmv @ 15% O_2 before combustor damage becomes significant. Higher diluent:fuel ratios (especially with steam) result in greater NOx reductions, but also increase emissions of CO and hydrocarbons, reduce turbine efficiency, and may increase turbine maintenance requirements. The principal NOx control mechanisms are identical for water and steam injection. Water or steam is injected into the primary combustion chamber to act as a heat sink, lowering the peak flame temperature of combustion and thus lowering the quantity of thermal NOx formed. The injected water or steam exits the turbine as part of the exhaust.

Since steam has a higher temperature/enthalpy than water, more steam is required to achieve the same quenching effect. Typical steam injection ratios are 0.5 to 2.0 pounds steam per pound fuel; water injection ratios are generally below 1.0 pound water per pound fuel. Because water has a higher heat absorbing capacity than steam (due to the temperature and to the latent heat of vaporization associated with water), it takes more steam than water to achieve an equivalent level of NOx control.

Although the lower peak flame temperature has a beneficial effect on NOx emissions, it can also reduce combustion efficiency and prevent complete combustion. As a result, CO and VOC emissions increase as water/steam-to-fuel ratios increase. Thus, the higher steam-to-fuel ratio required for NOx control will tend to cause higher CO and VOC emissions from steam-injected turbines than from water-injected turbines, due to the kinetic effect of the water molecules interfering with the combustion process. However, steam injection can reduce the heat rate of the turbine, so that equivalent power output can be achieved with reduced fuel consumption and reduced SO_2 emission rates.

Water and steam injection have been in use on both oil- and gas-fired turbines in all size ranges for many years so these NOx control technologies are clearly technologically feasible and widely available.

(ii) Dry Combustion Controls

Combustion modifications that lower NOx emissions without wet injection include lean combustion, reduced combustor residence time, lean premixed combustion and two-stage rich/lean combustion. Lean combustion uses excess air (greater than stoichiometric air-to-fuel ratio) in the combustor primary combustion zone to cool the flame, thereby reducing the rate of thermal NOx formation. Reduced combustor residence times are achieved by introducing dilution air between the combustor and the turbine sooner than with standard combustors. The combustion gases are at high temperatures for a shorter time, which also has the effect of reducing the rate of thermal NOx formation.

The most advanced combination of combustion controls for NOx is referred to as dry low-NOx (DLN) combustors. DLN technology uses lean, premixed combustion to keep peak combustion temperatures low, thus reducing the formation of thermal NOx. This technology is effective in achieving NOx emission levels comparable to levels achieved using wet injection without the need for large volumes of purified water and without the increases in CO and VOC emissions that result from wet injection. Several turbine vendors have developed this technology for their engines, including the engine proposed for this project. This control technique is technically feasible.

Catalytic combustors use a catalytic reactor bed mounted within the combustor to burn a very lean fuel-air mixture. This technology has been commercially demonstrated under the trade name XONON in a 1.5 MW natural gas-fired turbine in California and commercial availability of the technology for a 200 MW GE Frame 7G natural gas-fired turbine has been announced for one project. The combustor used in the demonstration engine is generally comparable in size to that used in GE Frame 7F engines; however, the technology has not been announced commercially for the Frame 7F engines proposed for this project. General Electric has indicated the technology is not yet commercially available. XONON is reported to be commercially available for 10 MW turbines manufactured by GE as well. No turbine vendor, other than General Electric, has indicated the commercial availability of catalytic combustion systems at the present time; therefore, catalytic combustion controls are not available for this specific application and are not discussed further.

(iii) Post-Combustion Controls

SCR is a post-combustion technique that controls both thermal and fuel NOx emissions by reducing NOx with a reagent (generally ammonia or urea) in the presence of a catalyst to form water and nitrogen. NOx conversion is sensitive to exhaust gas temperature, and performance can be limited by contaminants in the exhaust gas that may mask the catalyst (sulfur compounds, particulates, heavy metals, and silica). SCR is used in numerous gas turbine installations throughout the United States, almost exclusively in conjunction with other wet or dry NOx combustion controls. SCR requires the consumption of a reagent (ammonia or urea), and requires periodic catalyst replacement. Estimated levels of NOx control are in excess of 90%.

Selective non-catalytic reduction (SNCR) involves injection of ammonia or urea with proprietary conditioners into the exhaust gas stream without a catalyst. SNCR technology requires gas temperatures in the range of 1200° to 2000° F and is most commonly used in boilers. The exhaust temperature for the proposed gas turbine ranges from 1087° to 1200° F, well below the minimum SNCR operating temperature. Some method of exhaust gas reheat, such as additional fuel combustion, would be required to achieve exhaust temperatures compatible with SNCR operations, and this requirement makes SNCR technologically infeasible for this application. Even when technically feasible, SNCR is unlikely to achieve NOx reductions in excess of 80%-85%.

Nonselective catalytic reduction (NSCR) uses a catalyst without injected reagents to reduce NOx emissions in an exhaust gas stream. NSCR is typically used in automobile exhaust and rich-burn stationary IC engines, and employs a platinum/rhodium catalyst. NSCR is effective only in a stoichiometric or fuel-rich environment where the combustion gas is nearly depleted of oxygen, and this condition does not occur in turbine exhaust where the oxygen concentrations are typically between 14 and 16 percent. For this reason, NSCR is not technologically feasible for this application.

SCONOx is a proprietary catalytic oxidation and absorption technology that uses a single catalyst for the removal of NOx, CO, and VOC. The catalyst simultaneously oxidizes NO, CO, and VOCs and adsorbs NO_2 onto the catalyst surface where they are stored as nitrates and nitrites. The catalyst is a monolith design, made from a ceramic substrate, with a platinum-based catalyst and a potassium carbonate coating. The SCONOx catalyst has a limited adsorption capability, and requires regeneration on a cycle of approximately 12-15 minutes.[1] Regeneration occurs by dividing the SCONOx catalyst system in a series of sealable compartments. At any point in time, approximately 20% of the compartments in a SCONOx system would be in regeneration mode, and the remaining 80% of the compartments would be in oxidation/absorption mode.[2]

Regeneration of the SCONOx catalyst must occur in an oxygen-free environment. Consequently, each SCONOx compartment is equipped with front and rear seals to isolate the compartment from the exhaust gas stream during regeneration operation.

Regeneration is accomplished by passing a gas mixture (regeneration gases) containing methane, carbon dioxide and hydrogen over the catalyst beds.[3] Regeneration gases are created using a separate, external reformer. Initial attempts to create regeneration gases from natural gas and steam within the SCONOx catalyst bed (internal autothermal regeneration) failed to produce consistent results; this technology is not being proposed by ABB Environmental at the present time.[4]

The SCONOx catalyst bed, as designed for F-class gas turbines, includes a SCOSOx catalyst (or guard bed) followed by two or more SCONOx catalysts in series. The SCOSOx catalyst is intended to remove trace quantities of sulfur-bearing compounds from the exhaust gas stream, so as to avoid poisoning of the SCONOx catalyst. Like the SCONOx catalyst, the SCOSOx catalyst is regenerated. The regeneration for the two catalyst types occurs at the same time, with the same regeneration gas supply provided to both. Regeneration gases for the SCOSOx catalyst exit the module separately from the SCONOx regeneration gases; however, both regeneration gases are returned to the gas turbine exhaust stream downstream of the SCONOx module.[5]

The external reformer used to create the regeneration gases is supplied with steam and natural gas. For one F-class turbine, an estimated 15,000 to 20,000 lbs/hr of 600°F steam is required, along with approximately 100 pounds per hour (2.2 MMbtu/hr) of natural gas.[6] To avoid poisoning the reformer catalyst, the natural gas supplied to the reformer passes through an activated carbon filter

[1] Personal communication, ABB Environmental, 1/18/00.
[2] Stone & Webster, "Independent Technical Review – SCONOx Technology and Design Review", February 2000.
[3] Stone & Webster, op cit
[4] ABB Environmental, op cit
[5] ABB Environmental, op cit
[6] Ibid

to remove sulfur-bearing compounds.[7]

To properly treat the exhaust gas without undue backpressure, an estimated 40-60 catalyst modules would be required for an F-class machine.[8] (These modules are assembled, four to a shelf, to create 10-15 shelves.) The pressure drop associated with a NOx removal efficiency of 90% is approximately 5″ of water.[9] The estimated space velocity for such a system is 22,000/hour.[10]

The regeneration cycle time is expected to be controlled using a feedback system based on NOx emission rates.[11] That is, the higher the NOx emissions are relative to the design level, the shorter the absorption cycle, and regeneration cycles will occur more frequently. This is analogous to the use of feedback systems for controlling reagent (ammonia or urea) flow rates in an SCR system.

Maintenance requirements for SCONOx systems are expected to include periodic replacement of the reformer fuel sulfur carbon unit, periodic replacement of the reformer catalyst, periodic washings of the SCOSOx and SCONOx catalyst beds, and periodic replacement of the SCOSOx and SCONOx catalyst beds. The replacement frequency for the reformer sulfur carbon unit and reformer catalyst are unknown to Duke at present. The SCOSOx catalyst is expected to require washing once per year. The lead SCONOx catalyst bed is expected to require washing once per year, while the trailing SCONOx catalyst bed(s) are expected to require washing once every three years. The annual catalyst washing process is expected to take approximately three days for an F-class machine, with an estimated annual cost of $200,000.[12] The estimated catalyst life is reported to be 7 washings[13]; the guaranteed catalyst life is 3 years[14]

The absorption operating range for the SCONOx system is 300°F to 700°F, with an optimal temperature of approximately 600°F.[15] However, regeneration cycles are not initiated unless the catalyst bed temperature is above 450°F to avoid the creation of hydrogen sulfide during the regeneration of the SCOSOx catalyst.[16]

Estimates of control system efficiency vary. ABB Environmental has indicated that the SCONOx system is capable of achieving a 90% reduction in NOx, a 90% reduction in CO to a level of 2 ppm, and an 80%-85% reduction in VOC emissions.[17] (This VOC reduction is not likely to be achieved with low VOC inlet concentrations, in the 1 – 2 ppm range.[18]) Commercially quoted NOx emission rates for the SCONOx system range from 2.0 ppm on a 3-hour average basis, representing a 78% reduction[19], to 1.0 ppm with no averaging period specified (96% reduction)[20]. The SCONOx system does not control or reduce emissions of sulfur oxides or particulate matter from the combustion device.[21]

The SCONOx system has been applied at the Sunlaw Federal Cogeneration Plant in Vernon, California since December 1996, and at the Genetics Institute Facility in Massachusetts. The Sunlaw facility uses an LM-2500 gas turbine, rated at a nominal 23 MWe, and the Genetics Institute facility

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[7] Stone & Webster, op cit
[8] ABB Environmental, op cit
[9] Ibid
[10] Ibid
[11] Ibid
[12] Ibid
[13] Ibid
[14] Letter from ABB Alstom Power to Bibb & Associates dated May 5, 2000. (ABB Three Mountain Power or ABB TMP)
[15] Ibid
[16] ABB Environmental, op cit. Stone & Webster, op cit
[17] ABB Environmental, op cit
[18] Ibid
[19] ABB TMP, op cit
[20] Letter from ABB Alstom Power to Sunlaw Energy Corporation dated February 11, 2000. (ABB Sunlaw)
[21] ABB Environmental, op cit

has a 5 MWe Solar gas turbine. The SCONOx system was proposed for use by PG&E Generating Company at its La Paloma facility; however, PG&E Generating no longer plans to use the SCONOx system at that site.[22] In addition, the technology's co-developer, Sunlaw, has proposed to use the technology in conjunction with ABB gas turbines at the Nueva Azalea site in Southern California; however, that project has been suspended by the project developer. Finally, SCONOx is proposed for use at a 43 MW gas turbine under construction in Redding, California.

Based on the discussions above, the following NOx control technologies are available and potentially technologically feasible for the proposed project:

- Water injection
- Steam injection
- Dry Low-NOx Combustors
- Selective Catalytic Reduction
- SCONOx

c. Rank Remaining Control Technologies by Control Effectiveness

The remaining technically feasible control technologies are ranked by NOx control effectiveness in Table 8.1E-6.

Table 8.1E-6

NOx Control Alternatives

NOx Control Alternative	Available?	Technically Feasible?	NOx Emissions (@ 15% O_2)	Environmental Impact	Energy Impacts
Water Injection	Yes	Yes	25-42 ppm	Increased CO/VOC	Decreased Efficiency
Steam Injection	Yes	Yes	15 – 25 ppm	Increased CO/VOC	Increased Efficiency
Dry Low-NOx Combustors	Yes	Yes	9-25 ppm	Reduced CO/VOC	Increased Efficiency
Selective Catalytic Reduction	Yes	Yes	>90% reduction 1 – 2.5 ppm	Ammonia slip	Decreased efficiency
SCONOx	Yes[1]	Yes[2]	>90% reduction 1 – 2.5 ppm	Reduced CO; potential reduction in VOC	Decreased efficiency

Notes:

1. There are no standard, commercial guarantees for utility-scale projects for this technology available in the public domain.
2. Technology has been used on small (5 MW and 22 MW) gas turbines for a limited period of time. Has not been used on utility-scale gas turbines.

[22] Ibid

d. Evaluate Most Effective Controls and Document Results

Water and steam injection are control technologies that, for large gas turbines, have been largely superseded by dry low-NOx combustors, due to the superior emission control performance, additional CO and VOC benefits, and increased efficiency of this technology. Since the project proposes to use dry low NOx combustors, no further discussion of water injection, steam injection, or dry low NOx combustors is necessary.

The potential performance of SCR and SCONOx, insofar as NOx emission levels are concerned, is essentially equivalent. Both technologies have the potential to reduce NOx emissions by at least 90%, and differences between low NOx levels (1 ppm vs 2 ppm vs 2.5 ppm) appear, in the case of each technology, to be largely a function of catalyst size, turbine outlet NOx concentration, and compliance terms (e.g., averaging period). The principal differences between the two technologies are associated with whether the low emission levels proposed have been achieved in practice using these technologies, their cost-effectiveness in achieving these levels, and secondary environmental impacts.

Achieved in Practice Evaluation:

The SJVUAPCD has established formal criteria in its BACT policy for determining when emission control technologies should be considered achieved in practice (AIP) for the purposes of BACT determinations. The criteria include the following elements:

> Comparable Equipment: The rating and capacity of the unit where the control has been achieved must be approximately the same as that of the proposed unit.
>
> Class of Source: The type of business (that is, class of source) where the emissions units are utilized must be the same.
>
> Availability of Resources: The availability of resources (water, fuel, etc.) necessary for the control technology must be approximately the same.

Other factors considered in this evaluation are as follows:

> Commercial Availability: At least one vendor should offer this equipment for regular or full-scale operation in the United States. A performance warranty or guarantee should be available with the purchase of the control technology, as well as parts and service.
>
> Reliability: All control technologies should have been installed and operated reliably for at least six months. If the operator did not require the basic equipment to operate daily, then the equipment should have at least 183 cumulative days of operation. During this period, the basic equipment should have operated (1) at a minimum of 50% design capacity; or (2) in a manner that is typical of the equipment in order to provide an expectation of continued reliability of the control technology.
>
> Effectiveness: The control technology should be verified to perform effectively over the range of operation expected for that type of equipment. If the control technology will be allowed to operate at lesser effectiveness during certain modes of operation, then those modes of operation should be identified. The verification should be based on a performance test or tests, when possible, or other performance data.
>
> Technology Transfer: BACT is based on what is AIP for a category or class of source. However, USEPA and SJVUAPCD guidelines require that technology that is determined to be AIP for one category of source be considered for transfer to other source categories. There are two types of potentially transferable control technologies: (1) exhaust stream controls, and (2) process controls and modifications. For the first type, technology transfer must be considered between source categories that produce similar exhaust streams. For the second type, technology transfer must be considered between source categories with similar processes.

Discussion of SCR-Based Limits – Achieved in Practice Criteria

SCR has been achieved in practice at numerous gas turbine installations throughout the world. Although there are a large number of gas turbines equipped with SCR systems, there are relatively fewer systems in operation that are designed to meet low NOx permit limits of 2.5 ppm or less.

Available CEMS data from the SMUD/SPAC Campbell Soup plant in Sacramento, California, indicate NOx control levels on a continuous basis that are in compliance with a 3.0 ppm limit. Actual NOx levels from that facility, which is equipped with a 120 MW (nominal) Siemens V84.2 turbine, are comfortably below that limit, at approximately 2.5 ppm. This facility has experienced a limited number of events above the permit limit; in each case, the excursion has been associated with a trip of the gas turbine from pre-mix, or low-NOx, mode into diffusion mode. The permit for the facility has since been modified to accommodate up to ten hours per year of excursions above the 3 ppm permit limit under specified conditions.

The extrapolation of SCR experience gained at higher NOx concentrations (3-5 ppm), where there are more sites in operation, to lower NOx permit limits depends on controlling turbine exhaust (SCR inlet) NOx concentrations, increasing catalyst size, improving feed-forward and feed-back control system design to ensure better process control, and ensuring good distribution of reagent to match the distribution of NOx levels. The experience at the SMUD/SPAC site, however, indicates that the ability of the SCR system to track NOx emissions changes upstream of the catalyst is further challenged at progressively lower concentrations.

A further exacerbating factor is related to measurement uncertainty. The South Coast AQMD has indicated that current NOx measurement methods for stationary sources are accurate to ±1 ppm,[23] which becomes problematic at NOx permit levels of 5 ppm and lower.

The following paragraphs evaluate the proposed AIP criteria as applied to the achievement of extremely low NOx levels (2.5 ppm and lower) using SCR technology.

Comparable Equipment: SCR has been widely used on units of similar rating and capacity as that of the proposed units.

Class of Source: SCR has been widely used on utility-scale gas turbines, the same class of source as what is proposed for this project.

Availability of Resources: The necessary resources and other materials that are needed for the effective operation of SCR technology are available at the Project site.

Additional achieved in practice considerations are as follows:

Commercial availability: SCR technology is available with standard commercial guarantees for NOx levels at least as low as 1 ppm. Consequently, this criterion is satisfied.

Reliability: SCR technology has been shown to be capable of achieving NOx levels consistent with a 3 ppm permit limit during extended, routine operations of the SMUD/SPAC facility. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability.

[23] See, e.g., South Coast AQMD Protocol for Rule 2012.

Effectiveness: SCR technology has been demonstrated to achieve NOx levels below 3 ppm. At the SMUD/SPAC site, short-term excursions have resulted in NOx concentrations above 3 ppm; however, these excursions have not been associated with diminished effectiveness of the SCR system. Rather, these excursions have been associated with SCR inlet NOx levels in excess of those for which the SCR system was designed. Consequently, the application of SCR technology to achieve extremely low NOx levels should reflect the potential for infrequent NOx excursions, under specified conditions. Permits have been issued for at least two utility-scale projects that limit NOx emissions to not more than 2.0 ppm on a 1-hour average basis. However, neither of these facilities has commenced operation, and no assessment can be made of their ability to meet a 2.0 ppm, 1-hour average limit on a consistent basis.

Conclusion: SCR technology capable of achieving NOx levels below 3 ppm is considered to be achieved in practice. The proposed permit limits for the Project includes a NOx limit of 2.5 ppm on a 1-hour average basis. This proposed limit is consistent with the available data. The achievement of NOx concentrations below this level, on either a short term or long term basis, is not demonstrated in practice.

Discussion of SCONOx-Based Limits – Achieved in Practice Criteria

SCONOx has been demonstrated in service in two applications: the Federal Cogeneration Facility in Vernon, California, and the Genetics Institute Facility in Massachusetts. Because these turbines are much smaller than those proposed for the Project, issues related to the application of SCONOx technology to the Project need to be evaluated, in addition to a review of other criteria.

Comparable Equipment: The ratings and capacities of the units where SCONOx has been achieved are much smaller than those of the proposed units. Therefore, this criterion is not met.

Class of Source: Neither of the existing demonstration turbines is a utility-scale gas turbine with large duct burners. As the type of business (that is, class of source) where the emissions units are utilized are not the same, this criterion is not met.

Availability of Resources: SCONOx requires more water for washing of the reactor beds, and thus results in more wastewater for disposal. Although the water and fuel needed for operation of SCONOx technology are available at the Project site, the additional wastewater that would need to be treated and disposed of onsite is an environmental impact that should be considered.

Continuous emissions monitoring (CEMS) data from the Federal Vernon facility have been evaluated in stages, as the data have been made public. The results of these evaluations are presented below.

Available CEMS data from the Federal Vernon facility were obtained from EPA, covering the period July through December 1997. EPA had indicated that this time period reflected the improved performance of the SCONOx system, and led to EPA's March 23, 1998 letter regarding BACT and LAER requirements for combined cycle gas turbines.

A review of the available SCONOx data for the last half of 1997 indicates that, at the Federal site, up to 12 exceedances per year could be expected above a 3.0 ppm, 3-hour average limit, even when exceedances related to startups and shutdowns were excluded.[24]

EPA and the California Air Resources Board have recommended BACT/LAER levels for combined cycle gas turbines of either 2.0 ppm on a 3-hour average basis, or 2.5 ppm on a 1-hour average basis.

[24] For the purposes of the reviews of SCONOx presented in this report, a startup for the LM-2500 gas turbine at the Federal Vernon facility was defined as a period not to exceed 120 minutes; a shutdown was defined as a period not to exceed 60 minutes. These definitions are conservative in that aeroderivative gas turbines, such as those in use at the Vernon facility, are generally capable of completing a startup, with all emission control systems active, within 30 minutes, and are capable of completing a shutdown within 15 minutes. Permits for many LM-2500 combined cycle facilities expressly limit startups to not more than 30 or 60 minutes.

Under the BACT/LAER levels recommended by these agencies, the 1997 SCONOx data from the Federal site indicate that a 3-hour average limit of 2.0 ppm would be exceeded 44 times per year, and a 1-hour average limit of 2.5 ppm would be exceeded 24 times per year. Again, these data exclude exceedances associated with startups and shutdowns, as described above.

The data supporting these conclusions are shown in Table 8.1E-7.

The first part of this table shows, by month and quarter, the number of all 1-hour and 3-hour exceedances of various NOx emissions levels associated with operation of the SCONOx system during the period that resulted in EPA's March 1998 letter. The second part of the table shows exceedances that were not due to turbine startups or shutdowns.

Table 8.1E-7
SCONOx Performance – Summary Prepared by Sierra Research
July 1, 1997 to December 31, 1997

SCONOx Excursions Review										
All excursions:										
	No. of Valid	CEMS	No. of 1-hr periods exceeding			No. of 3-hr periods exceeding			Highest reading	
Month	CEMS Hrs	Avail, %	2.0 ppmc	2.5 ppmc	3.0 ppmc	2.0 ppmc	2.5 ppmc	3.0 ppmc	1-hr avg	3-hr avg
Jul	739.00	99.33	3	3	2	1	0	0	4.2	2.3
Aug	741.00	99.60	4	3	2	5	0	0	4.4	2.2
Sept	715.00	99.31	3	2	2	3	2	2	5.0	3.7
Quarter	**2195.00**	**99.41**	**10**	**8**	**6**	**9**	**2**	**2**	**5.0**	**3.7**
Oct	731.00	98.25	9	5	5	10	9	8	10.9	7.5
Nov	716.00	99.44	18	16	14	29	19	14	9.6	6.3
Dec	723.00	97.18	6	4	2	7	4	1	5.4	3.2
Quarter	**2170.00**	**98.28**	**33**	**25**	**21**	**46**	**32**	**23**	**10.9**	**7.5**
Excursions not due to startups or shutdowns:										
	No. of Valid	CEMS	No. of 1-hr periods exceeding			No. of 3-hr periods exceeding			Highest reading	
Month	CEMS Hrs	Avail, %	2.0 ppmc	2.5 ppmc	3.0 ppmc	2.0 ppmc	2.5 ppmc	3.0 ppmc	1-hr avg	3-hr avg
Jul	739.00	99.33	1	1	0	0	0	0	2.6	1.8
Aug	741.00	99.60	3	2	1	4	0	0	3.5	2.2
Sept	715.00	99.31	1	0	0	0	0	0	2.2	2.0
Quarter	**2195.00**	**99.41**	**5**	**3**	**1**	**4**	**0**	**0**	**3.5**	**2.2**
Oct	731.00	98.25	5	3	3	5	5	5	10.9	7.5
Nov	716.00	99.44	5	4	3	8	2	1	8.6	3.8
Dec	723.00	97.18	4	2	1	5	2	0	4.0	2.8
Quarter	**2170.00**	**98.28**	**14**	**9**	**7**	**18**	**9**	**6**	**10.9**	**7.5**
Note:	All NOx readings corrected to 15% oxygen.									

In this analysis, no more than 2 hours of NOx emissions following a startup were treated as part of the startup. For the 3-hour averages, any average that included a startup hour was attributed to the startup. This is in contrast with the approach taken by Goal Line Environmental Technologies (GLET) in its comments accompanying the data reports, in which it is clear that startup periods were considered to extend as much as 6 hours. (This is particularly inappropriate for aeroderivative turbines such as those used at the Federal facility, which are known for their ability to start within tens of minutes.) NOx emissions greater than 2 ppm occurring during these long startup periods were reported by GLET, but were not considered to be exceedances.

In summary, using a 2-hour startup period for aeroderivative gas turbines, the data reported by GLET to EPA for 1997 do not support a BACT determination below 3 ppm. Based solely on the SCONOx data presented to EPA, even a NOx limit at 3.0 ppm would have to provide for excursions, other than startups and shutdowns, above that limit. The number of excursions needed would depend upon the NOx limit selected and the emission control technology employed.

Additional data have been generated at the Federal site, and were provided to EPA Region IX by CURE.[25] These data were for the period April 1, 1999 through December 31, 1999, and were

[25] Letter dated March 14, 2000, from Katherine Poole, Adams Broadwell Joseph & Cardozo, to Steve Branoff, EPA Region IX.

provided to Sierra Research by EPA Region IX.[26] The more recent data are consistent with the earlier data, and are summarized in Table 8.1E-8.

The 1999 CEMS data from the Federal facility indicated that the turbine equipped with SCONOx was operated fewer than 2,600 hours during the nine-month period for which data were provided. During this period, the turbine was started 149 times. The CEMS data for CO, in particular, are suspect; more than 60% of the CO values reported were less than zero, indicating that the CO analyzer was not properly calibrated on a daily basis. For this reason, the CO data for this period were not analyzed further.

The NOx emissions data for this period were analyzed to evaluate compliance with five hypothetical emission limits (3.0, 2.5, 2.0, 1.5, and 1.3 ppm) and three compliance averaging periods (15 minute, 1 hour, 3 hour). Valid data periods were considered to be those that excluded startups, shutdowns, and initiation of fuel flow to the engine, and lasting until the NOx emission limit under evaluation was met, but not exceeding a period of two hours. Shutdown periods were defined to be periods ending with the cessation of documented CEMS maintenance. Startups were defined to be periods commencing with the fuel flow to the engine and starting when the NOx emission limit under evaluation was no longer met, but not exceeding a period of 30 minutes. A valid 1-hour average period was defined to require at least two valid 15-minute periods; a valid 3-hour average period was defined to require at least two valid 1-hour average periods. All of the above definitions are typical for utility-scale gas turbine CEMS systems.

[26] Letter dated June 28, 2000 from Duong Nguyen, EPA Region IX, to Nancy Matthews, Sierra Research.

Table 8.1E-8

SCONOx Performance – Summary Prepared by Sierra Research

April 1, 1999 to December 31, 1999

Plant Statistics

Total Hours in Review Period	6,400	
Number of Operating Hours	2,583	
Number of Turbine Starts	149	
Number of CEM Data Periods with Turbine Operating	10,331	
Number of negative CEM values		
NOx:	0	0%
CO:	6,494	63%

Valid Data Periods (Excludes Startup/Shutdown, CEM Maintenance)

NOx Limit (ppm) -> Averaging Period	**3.0**	**2.5**	**2.0**	**1.5**	**1.3**
15 min	9,861	9,813	9,742	9,649	9,607
1 hour	2,501	2,491	2,470	2,445	2,434
3 hour	2,498	2,488	2,468	2,445	2,434

Exceedance Periods (Excludes Startup/Shutdown, CEM Maintenance)

NOx Limit (ppm) -> Averaging Period	**3.0**	**2.5**	**2.0**	**1.5**	**1.3**
15 min	71	77	92	111	124
1 hour	18	21	24	29	32
3 hour	20	22	26	32	36

The data indicated that there were 9,600 to 9,900 valid 15-minute periods, excluding startups, shutdowns, and CEMS maintenance, depending on the NOx limit being evaluated. There were numerous exceedances of the hypothetical NOx limits during these periods, ranging from 71 periods in which NOx emissions exceeded 3.0 ppm to 124 periods in which NOx emissions exceeded 1.3 ppm.

There were approximately 2,500 valid 1-hour average periods in the data set, excluding startups, shutdowns, and CEMS maintenance. For 1-hour average limits, the data again showed numerous exceedances, ranging from 18 exceedances of a 3.0 ppm NOx limit to 32 exceedances of a 1.3 ppm limit. Finally, during the approximately 2,500 valid 3-hour average periods in the data set, there were 20 exceedances of a 3.0 ppm limit and 36 exceedances of a 1.3 ppm NOx limit.

In summary, these more recent data fail to support the conclusion that the SCONOx system at the Federal facility is capable of consistently maintaining low NOx levels of 3.0 ppm or less. Depending on the NOx limit evaluated, the periods of non-compliance over a nine-month period ranged from 18 to 32 hours, excluding periods of turbine startup, shutdown, and CEMS maintenance. While each of the exceedances was accompanied in the data file with an explanation, these explanations do not eliminate the exceedances. In fact, of the 24 exceedances of a 3.0 ppm NOx limit on a 1-hour average basis observed in the 1999 data, 14 were explicitly attributed to problems with the SCONOx system in the file presenting the CEMS data.

More recently, Goal Line Environmental has made available CEMS data from a five-month period in 2000. The 2000 CEMS data from the Federal facility indicated that the turbine equipped with SCONOx was operated for approximately 2,000 hours during this five-month period. During this period, the turbine was started 135 times. The CEMS data for CO remain suspect; approximately 28% of the CO values reported were less than zero, indicating that the CO analyzer was not properly calibrated on a daily basis. For this reason, the CO data for this period were not analyzed further.

As with the 1999 data, the NOx emissions data for this period were analyzed to evaluate compliance with five hypothetical emission limits (3.0, 2.5, 2.0, 1.5, and 1.3 ppm) and three compliance averaging periods (15 minute, 1 hour, 3 hour). The same criteria used for the 1999 data for determining valid data periods, startup periods, and shutdown periods were used for the 2000 CEMS data. The data for 2000 are shown in Table 8.1E-9.

Table 8.1E-9

Sunlaw Cogeneration Partners
SCONOx Performance - Summary Prepared by Sierra Research
April 1, 2000 to August 31, 2000

Plant Statistics

Total Hours in Review Period	3,672	
Number of Operating Hours	2,021	
Number of Turbine Starts	135	
Number of CEM Data Periods with Turbine Operating	18,995	
Number of negative CEM values		
NOx:	0	0%
CO:	5,330	28%

Valid Data Periods (Excludes Startup/Shutdown, CEM Maintenance)

NOx Limit (ppm) -> **Averaging Period**	**3.0**	**2.5**	**2.0**	**1.5**	**1.3**
15 min	7,690	7,615	7,532	7,422	7,371
1 hour	2,003	1,994	1,967	1,931	1,913
3 hour	2,001	1,992	1,963	1,927	1,908

Exceedance Periods (Excludes Startup/Shutdown, CEM Maintenance)

NOx Limit (ppm) -> **Averaging Period**	**3.0**	**2.5**	**2.0**	**1.5**	**1.3**
15 min	45	50	59	74	84
1 hour	15	18	20	22	27
3 hour	16	19	21	25	29
Annualized Basis **Averaging Period**					
15 min	108	120	142	178	202
1 hour	36	43	48	53	65
3 hour	38	46	50	60	70

The data indicated that there were 7,300 to 7,700 valid 15-minute periods, excluding startups, shutdowns, and CEMS maintenance, depending on the NOx limit being evaluated. There were numerous exceedances of the hypothetical NOx limits during these periods, ranging from 108 periods in which NOx emissions exceeded 3.0 ppm to 202 periods in which NOx emissions exceeded1.3 ppm.

There were approximately 2,000 valid 1-hour average periods in the data set, excluding startups, shutdowns, and CEMS maintenance. For 1-hour average limits, the data again showed numerous exceedances, ranging from 36 exceedances of a 3.0 ppm NOx limit to 65 exceedances of a 1.3 ppm limit. Finally, during the approximately 2,000 valid 3-hour average periods in the data set, there were 38 exceedances of a 3.0 ppm limit and 70 exceedances of a 1.3 ppm NOx limit.

As was the case with the 1999 CEMS data, the 2000 CEMS data fail to demonstrate that the SCONOx system is capable of achieving NOx levels considered to represent BACT on a consistent basis.

Table 8.1E-10 compares the results of the analyses of the 1997, 1999, and 2000 data, with all three data sets normalized to predict exceedances over a 12-month period.

The more recent data do not indicate improved performance as compared with the 1997 CEMS data.

Table 8.1E-10
Comparison of 1997, 1999 and 2000 SCONOx CEMS Data
Exceedances of Hypothetical Permit Limits – Annualized Basis
(Excluding startups/shutdowns/CEMS maintenance)

Data Set	1-hour average			3-hour average		
	3.0 ppm limit	2.5 ppm limit	2.0 ppm limit	3.0 ppm limit	2.5 ppm limit	2.0 ppm limit
1997	16	24	38	12	18	44
1999	24	28	32	26	29	34
2000	36	43	48	38	46	50

In addition to performance-related issues regarding SCONOx, there are concerns regarding the demonstration of durability of the regeneration gas and damper/sealing systems, and the ability of the SCONOx system to respond to transient conditions that result in changes in turbine-exhaust NOx levels.

With respect to the damper/sealing system, there have been three different designs discussed in technical literature regarding SCONOx. Table 8.1E-11 summarizes these designs.

Table 8.1E-11 Summary of SCONOx Installations			
	Federal Cogeneration[1]	**Genetics Institute**[1]	**Proposed Future (F-class turbine)**
Regeneration Gas System			
Regeneration system type	Direct hydrogen injection	External reformer	External reformer
Regen Gas Flow Rate	1520 acfm	1050 acfm	
SCOSOx (Guard Bed) Catalyst System			
Cell Density	Not installed (periodic water washing of catalyst is performed instead)		
Substrate			
Catalyst Volume		26.25 cu ft	
Space Velocity - Absorption - Regeneration	 	 116,630 6,000	 114,000 4,000
Cycle Times - Absorption - Regeneration		 12 min 3 min	
SCONOx Catalyst System			
Cell Density	230	230	
Substrate	Ceramic	Ceramic	
Catalyst Volume	294 cu ft	157.5 cu ft	
Space Velocity - Absorption - Regeneration	 11,100 275	 19,440 1,000	 22,000 750
Cycle Times - Absorption - Regeneration	 12 min 4 min	 12 min 3 min	
Damper/Seal Systems			
Number of Modules	4	5	40-60[2]
Number of Dampers	12	10	80-120[2]
Damper Type	Louver, flap type	Louver, flap type	Louver, flap type
Damper Support	End supported	Center supported	Center supported
Misc			
Seal Material/Type	316 SS, 'S' type	Fiberglass/stainless steel wool tadpole design	
Actuator Type	Electrical	Electrical	

Notes:

1. Stone & Webster, op cit
2. Modules are joined, four together, to form linked "shelves."

Stone and Webster reported that the initial operation of the SCONOx system at the Genetics Institute facility resulted in a rapid loss of performance due to a lack of regeneration. This problem was traced to mechanical deficiencies, including seal and gasket leakage. Corrective actions taken included replacement of the flexible metal damper seals with tadpole seals, installation of a manual throttling valve in the gas return line, re-gasketing and re-sealing of the heat exchanger flanges, and adjustment of the damper actuators. Further changes to the overall system included adding an external reformer, adding a sulfur filter to remove sulfur from the gas that feeds the external reformer, and modifying the damper/seal system.

Although the damper/sealing system was subjected to a 101,000 cycle test (equivalent to approximately 25,000 operating hours based on 15-minute cycle times), Stone & Webster reported that a number of damper/seal design changes have been proposed by ABB based on those test results. These changes include a modification to the tadpole design to avoid excessive stress at the location where the damper blade rests on the seal, and modifications to the shaft design to preclude leaks associated with fabric failure near the shaft-seal interface.

As of the date of their report (February 22, 2000), Stone & Webster indicated that full-scale testing of the new seal design had not been performed. In particular, Stone & Webster noted that “the use of fiberglass in the temperature range of 600°F to 700°F with frequent flexing and relaxing, over the expected design period of three years, is yet to be demonstrated.” Although ABB has issued a subsequent letter report addressing the concerns raised by Stone & Webster, there is no supplemental, independent engineering review in the public domain to confirm ABB’s conclusions.

Based on this information, the following paragraphs evaluate the supplemental AIP criteria as applied to the achievement of extremely low NOx levels (2.5 ppm and lower) using SCONOx technology.

Commercial availability: It is not clear whether SCONOx technology is presently available with standard commercial guarantees for NOx levels at least as low as 2.5 ppm. A request for a copy of the guarantee for SCONOx performance from the developers of the Otay Mesa Generating Project was rejected. An excerpt of the guarantee from the system vendor to Sunlaw Energy, a co-developer of the SCONOx system, was included as an appendix to the Application for Certification for the Nueva Azalea project. However, this guarantee is between two parties with a common financial interest in the demonstration and sale of the SCONOx system, and thus is not necessarily representative of a standard commercial guarantee. Public statements by ABB Environmental, the exclusive licensee of the SCONOx system for gas turbines with a capacity greater than 100 MW, indicate that standard commercial performance guarantees will be provided for this system upon request. It is unclear, however, whether this guarantee will be passed on by the HRSG vendors and/or EPC contractors, as is standard in the industry. In fact, a potential supplier of an HRSG system for a power plant project in California has indicated, in writing, that the supplier would not back up ABB’s performance guarantees or warranty claims because the supplier was “not comfortable with the scale up from the existing size of the current technology.”[27] Thus, it is possible that this criterion is satisfied but, as yet, there is no publicly available documentation to support such a conclusion. The only publicly available documentation indicates that SCONOx is <u>not</u> commercially available for F-class turbines with standard commercial performance guarantees.

Reliability: To date, there have been no unqualified demonstrations of the ability of the SCONOx system to meet NOx levels of 3 ppm or lower over extended periods of time. The demonstrations at the Federal Cogeneration facility have indicated numerous circumstances under which a 3 ppm level would be exceeded (excluding startup and shutdown conditions), with data from as recently as 2000

[27] Telefax message dated June 15, 2000 from Aalborg Industries to Duke/Fluor-Daniel.

having been evaluated. Furthermore, the SCONOx system at the Federal facility uses a different scheme for catalyst regeneration, sulfur protection, and dampers/sealing than that proposed for use in a full-scale, commercial project. The catalyst regeneration system used at the Federal facility involved direct hydrogen injection to the catalyst bed; this system appears to have been rejected for use by ABB Environmental for larger, utility-scale applications. The current sulfur protection system for the SCONOx catalyst (the SCOSOx guard bed system) was not used at the Federal facility, and the sulfur protection system used at the Federal facility (periodic water washing of catalyst elements) appears to have been rejected by ABB Environmental for larger, utility-scale applications. Finally, the end-supported damper system with metal seals used at the Federal facility appears to have been rejected by ABB Environmental for larger, utility-scale applications. Consequently, the Federal facility is not indicative of the reliability of the SCONOx system for utility-scale applications.

The SCONOx installation at the Genetics Institute facility currently uses the new designs for catalyst regeneration, sulfur protection, and dampers/sealing. However, problems associated with that facility's ability to consistently meet NOx levels lower than 2.5 ppm were reported as recently as January 2001.[28] As a result of these problems, the Genetics Institute has sought and received a permit modification that extends the SCONOx demonstration period through April 2002. The current NOx permit limit applicable to the Genetics Institute SCONOx facility is 25 ppm. Consequently, the Genetics Institute facility does not yet constitute a demonstration that the SCONOx system can reliably meet NOx levels of less than 2.5 ppm.

Furthermore, the revised damper/seal system in use at the Genetics Institute facility has not been fully tested in field service, as noted by Stone & Webster. The next-prior version of the damper/seal system, which was tested for ABB Environmental in a test facility, exhibited failures of various kinds after approximately 60,000 cycles. Improvements to the damper/seal system to address those failures have not been similarly tested (or, at least, the reports of any such tests have not been presented publicly). Since an F-class gas turbine is expected to require the use of 40-60 modules, with 40-60 pairs of dampers/seals, 40-60 shaft actuators, and approximately 2.7 million damper-cycles per turbine per year,[29] it is unclear that the performance tests conducted to date demonstrate the ability of this portion of the system to ensure compliance with sub-3 ppm NOx levels on a continuous basis.

Effectiveness: As discussed above, the Federal facility uses different catalyst regeneration, sulfur protection, and sealer/damper systems than those being offered for F-class turbines by ABB Environmental. Thus, it is not clear that the Federal installation can be used to demonstrate the effectiveness of the systems being proposed for larger, utility-scale projects. The SCONOx configuration at the Genetics Institute facility is more similar to that proposed for larger turbines; however, that facility "has met or exceeded the performance requirement of 2.5 ppm [NOx] for approximately 330 hours, out of the total hours of operation of approximately 410 hours for which valid data is available."[30] This means that the 2.5 ppm NOx performance target was <u>not</u> met during approximately 20% of the hours within this period. As noted above, many of the exceedances of the 2.5 ppm NOx level at the Genetics Institute site were attributable to operation of the gas turbine's transient pilot. More recent data from the Genetics Institute site indicate that the NOx permit limit of 2.5 ppm was exceeded during 14% of operating hours in the fourth quarter of 2000

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[28] Letter dated January 15, 2001 from Genetics Institute to EPA Region I indicating that NOx emissions in excess of 2.5 ppm were experienced during 13.7% of the plant's operating time in the fourth quarter of 2000 due to control equipment problems.
[29] Calculated as 40 pairs of dampers per turbine, 2 dampers per pair, 4 cycles per damper per hour, 8400 operating hours per year: 40 x 2 x 4 x 8400 = 2,688,000 damper cycles per year per turbine.
[30] Stone & Webster, op cit

due to control equipment problems. Consequently, the available data from that site are not sufficient to conclude that NOx levels of 2.5 ppm or less can be achieved using the SCONOx system on a consistent basis, nor are the available data from the Federal site suitable for reaching such a conclusion. At a minimum, if SCONOx technology were used to achieve extremely low NOx levels, permit conditions would need to reflect the potential for frequent NOx excursions under specified conditions.

Conclusion: SCONOx technology has been found to be capable of achieving NOx levels below 2.5 ppm by the South Coast AQMD and EPA. However, the presently available technical information does not support a conclusion that this technology is achieved in practice based on the applicable guidelines.

e. Select BACT

Based on the above analysis, both SCR and SCONOx-based systems are considered, in general, to be technologically capable of achieving NOx levels below 2.5 ppm, given appropriate consideration to turbine outlet NOx levels, catalyst volume (space velocity) and control system design. For both types of systems, some provision will be necessary to accommodate short-term excursions above permit limits, and for both types of systems, particular attention to CEMS design will be necessary to ensure that low permit limits can be monitored on a continuous and accurate basis.

Based on this information, BACT for NOx is considered to be the use of either SCR or SCONOx systems to achieve NOx levels not higher than 2.5 ppm on a 1-hour average basis, or 2.0 ppm on a

3-hour average basis. The Project proposes to use SCR technology to meet a NOx level of 2.5 ppm on a 1-hour average basis, and 2.0 ppm on an annual average basis. Consequently, the Project is consistent with BACT requirements.

2. <u>Control of Ammonia Emissions</u>

a. Identify all control technologies

Ammonia emissions result from the use of ammonia-based NOx control technologies. Consequently, only an abbreviated discussion of these technologies is restated here.

There are three basic means of controlling NOx emissions from combustion turbines: wet combustion controls, dry combustion controls, and post-combustion controls. These technologies were discussed above.

Water and steam injection are control technologies that, for large gas turbines, have been largely superseded by dry low-NOx combustors, due to the superior emission control performance, additional CO and VOC benefits, and increased efficiency of this technology. Since the project proposes to use dry low NOx combustors, no further discussion of water injection, steam injection, or dry low NOx combustors is necessary.

b. Eliminate technically infeasible options

The performance of SCR and SCONOx, insofar as NOx emission levels are concerned, has been discussed above.

c. Rank remaining control technologies by control effectiveness

SCONOx results in no emissions of ammonia, while SCR results in ammonia slip levels of up to

10 ppm. The following discussion evaluates potential ammonia slip limits of 10 ppm, 5 ppm, 2 ppm, and 0 ppm. The latter limit would be achievable, at the present time, only through the use of

SCONOx technology.

d. Evaluate most effective controls and document results

SCR has been achieved in practice at numerous gas turbine installations throughout the world. Although there are a large number of gas turbines equipped with SCR systems, there are relatively fewer operating systems that are designed to meet low NOx permit limits of 3.0 ppm or less. Ammonia slip associated with SCR system operation results from a gradual decline in catalyst activity over time, necessitating the use of increasing amounts of ammonia injection to maintain NOx concentrations at or below the design rate.

The parameters of NOx concentration, ammonia slip limit, and catalyst life are integrally related. That is, catalyst performance is generally specified as being a particular NOx concentration

(e.g., 2.5 ppm), guaranteed for N years (e.g., 3 years), with a maximum ammonia slip level of X ppm (e.g., 5 ppm). Such a specification indicates that catalyst performance will degrade over time such that at the end of three years, ammonia slip will increase to not more than 5 ppm while maintaining NOx concentrations at or below 2.5 ppm. During the early period of performance, ammonia slip from an oxidation catalyst is typically less than 1-2 ppm, and will approach the guarantee level only towards the end of the catalyst life.

Early SCR installations, as well as some later installations, have been associated with ammonia slip levels of 10 ppm. In August 1999, the California Air Resources Board adopted a BACT guideline for large gas turbines that proposed to limit ammonia slip to not more than 5 ppm. Ammonia slip levels of 2 ppm have been required in several permits issued in the eastern United States. However, these permits have typically been associated with higher NOx levels than are proposed here. In particular, the 2 ppm ammonia slip limits have been proposed in conjunction with NOx levels that range between 2.0 and 3.5 ppm, depending on operating mode. Although the Project is proposing a 1-hour average NOx limit of 2.5 ppm, the facility is also proposing an annual average goal of 2.0 ppm.

Finally, SCONOx has the potential to achieve this low a NOx level without any ammonia slip.

Consequently, the following discussion compares the use of SCR with a 10 ppm ammonia slip level with SCONOx to meet comparable NOx levels, but without any ammonia slip.

SCR technology is available with standard commercial guarantees with ammonia slip levels of 10, 5, and 2 ppm, in conjunction with NOx levels at least as low as 2 ppm. However, we are unaware of any commercial guarantees for NOx levels of 1 ppm and ammonia slip levels of 2 ppm.

SCR technology has been shown to be capable of achieving ammonia slip levels below 5 ppm over at least a three-year catalyst life period. There are no reported adverse effects of operation of the SCR system at these levels on overall plant operation or reliability.

The SJVUAPCD's web site lists two SCR-based BACT determinations for ammonia slip from the mid-90s. These projects were permitted at 20 and 25 ppmvd NH_3 @ 15% O_2. More recent permit decisions have included 10 ppm ammonia slip levels, consistent with the level proposed for the Project.

One of these more recent SCR-based BACT determinations for ammonia slip is for the La Paloma Generating project, which was approved by the District in October 1999. This project is required to meet a 10 ppm ammonia slip limit on a 24-hour average basis in conjunction with a 2.5 ppm NOx limit on a 1-hour average basis.

These permits indicate that, as recently as one year ago, ammonia slip limits of 10 ppm were considered best available control technology. The rapid changes during the last year are indicative of increasing confidence of SCR system vendors in sustaining low ammonia slip rates in conjunction with low NOx emission rates. However, given the lack of any real-world demonstration of these low NOx and ammonia slip levels at the present time, BACT for ammonia slip using SCR-based controls is considered to be 10 ppm for this project.

Consequently, if an SCR-based control system is selected, BACT for ammonia slip should be an emission limit of 10 ppm.

Since SCONOx technology to eliminate ammonia slip may be technologically feasible, a further evaluation of the cost/effectiveness of this technology was performed. In this analysis, the cost of a SCONOx system was compared with the cost of an SCR and oxidation catalyst system, with the incremental cost assigned to the benefit of eliminating ammonia slip emissions. (It is appropriate to make such an assignment because the performance of the SCR and oxidation catalyst systems is comparable to that proposed for SCONOx with respect to NOx and CO emission levels for this project.)

As shown in Tables 8.1E-12a through 12d, the results of this analysis indicate that the incremental cost/effectiveness of the SCONOx system for the purpose of reducing ammonia emissions is nearly $50,000 per ton.

The SJVUAPCD publishes cost/effectiveness criteria for use in performing BACT analyses. The BACT cost/effectiveness threshold for PM_{10}, $5700/ton, is used to provide a reference for the calculated cost/effectiveness of SCONOx as an ammonia control device. Since ammonia is regulated as a precursor to PM_{10}, this value is used to represent a BACT cost/effectiveness threshold for ammonia control.

While this value is not, by itself, determinative, it indicates that the cost/effectiveness of using SCONOx to eliminate ammonia emissions is well in excess of the cost that is normally required for the control of PM_{10} in BACT determinations in the San Joaquin Valley, where the state and/or federal PM_{10} air quality standards are exceeded.

e. Select BACT

Based on the above information, BACT for ammonia is considered to be an ammonia slip limit of

10 ppm. SCONOx has the potential to eliminate ammonia emissions; however, this candidate technology was rejected for the reasons discussed above.

The Project proposes to use SCR technology to meet an ammonia slip limit of 10 ppm in conjunction with NOx levels of 2.5 ppm on a 1-hour average basis and 2.0 ppm on an annual average basis. Consequently, Duke’s proposal is consistent with BACT requirements for ammonia emissions.

Table 8.1E-12a

SCR Costs (per gas turbine/HRSG)

Description of Cost	Cost Factor	Cost ($)	Notes
Direct Capital Costs (DC):			
Purchased Equip. Cost (PE):			
Basic Equipment:			
Auxiliary Equipment: HRSG tube/ fin modifications			
Instrumentation: SCR controls			
Ammonia storage system:			
Taxes and freight:			
PE Total:		$1,620,000	1
Direct Install. Costs (DI):			
Foundation & supports:	0.08 PE	$129,600	2
Handling and erection (included in PE cost):		$0	1
Electrical (included in PE cost):		$0	1
Piping (included in PE cost):		$0	1
Insulation (included in PE cost):		$0	1
Painting (included in PE cost):		$0	1
DI Total:		$129,600	
Site preparation for ammonia tanks		$10,000	1
DC Total (PE+DI):		$1,759,600	
Indirect Costs (IC):			
Engineering:	0.10 PE	$162,000	2
Construction and field expenses:	0.05 PE	$81,000	2
Contractor fees:	0.10 PE	$162,000	2
Start-up:	0.02 PE	$32,400	2
Performance testing:	0.01 PE	$16,200	2
Contingencies:	0.05 PE	$81,000	1
IC Total:		$534,600	
Less: Capital cost of initial catalyst charge		-$975,000	
Total Capital Investment (TCI = DC + IC):		$1,319,200	
Direct Annual Costs (DAC): 0.5 hr/ SCR per shift	hr/ yr: 4,380		
Operating Costs (O): sched. (hr/ day 24; day/ week: 7	wk/ yr: 52		
Operator: hr/ shift: 1.0; operator pay ($/ hr):	39.20	$42,806	2
Supervisor: 15% of operator		$6,421	2
Maintenance Costs (M): 0.5 hr/ SCR per shift			
Labor: hr/ shift: 1.0; labor pay ($/ hr):	39.2	$42,806	2
Material: % of labor cos 100%		$42,806	2
Utility Costs:			
Perf. loss: (kwh/ unit): 347.6			1
Electricity cost ($/ kwh): 0.0336; Performance loss cost penalty:		$102,311	5
Ammonia based on 153 lbs/ hr of 24.5% wt aqueous ammonia, $0.05/ lb		$73,883	1, 4
Catalyst replace: based on 3 year catalyst life		$325,000	1
Catalyst dispose: based on 2,750 ft^3 catalyst, $15/ ft^3, 3 yr. Life		$13,750	1
Total DAC:		$649,784	
Indirect Annual Costs (IAC):			
Overhead: 60% of O&M		$80,904	2
Administrative:	0.02 TCI	$26,384	2
Insurance:	0.01 TCI	$13,192	2
Property tax:	0.01 TCI	$13,192	2
Total IAC:		$133,672	
Total Annual Cost (DAC + IAC):		$783,456	
Capital Recovery (CR):			
Capital recovery: interest rate (%) 10			
period (years): 15	0.1315	$173,440	2
Total Annualized Costs		$956,897	

Table 8.1E-12b

Oxidation Catalyst Costs (per gas turbine/HRSG)

Description of Cost				Cost Factor		Cost ($)	Notes
Direct Capital Costs (DC):							
Purchased Equip. Cost (PE):							
Basic Equipment:							
Auxiliary Equipment: HRSG tube/fin modifications							
Instrumentation: oxidation cat. Controls							
Taxes and freight:							
PE Total:						$725,000	1
Direct Install. Costs (DI):							
Foundation & supports:				0.08 PE		$58,000	2
Handling and erection (included in PE cost):						$0	1
Electrical (included in PE cost):						$0	1
Piping (included in PE cost):						$0	1
Insulation (included in PE cost):						$0	1
Painting (included in PE cost):						$0	1
DI Total:						$58,000	
DC Total (PE+DI):						$783,000	
Indirect Costs (IC):							
Engineering:				0.10 PE		$72,500	2
Construction and field expenses:				0.05 PE		$36,250	2
Contractor fees:				0.10 PE		$72,500	2
Start-up:				0.02 PE		$14,500	2
Performance testing:				0.01 PE		$7,250	2
Contingencies:				0.05 PE		$36,250	1
IC Total:						$239,250	
Less: Capital cost of initial catalyst charge						-$350,000	
Total Capital Investment (TCI = DC + IC):						$672,250	
Direct Annual Costs (DAC):				hr/yr:	4,380		
Operating Costs (O):	sched. (hr/day	24	day/week: 7	wk/yr:	52		
Operator:	hr/shift:	0.0	operator pay ($/hr):	39.20		$0	2
Supervisor:	15% of operator					$0	2
Maintenance Costs (M): 0.5 hr/oxidation cat. per shift							
Labor:	hr/shift:	0.0	labor pay ($/hr):	39.2		$0	2
Material:	% of labor cos	100%				$0	2
Utility Costs:							
Perf. loss:	(kwh/unit):	172.5					1
Electricity cost	($/kwh):	0.0336	Performance loss cost penalty:			$50,773	5
Catalyst replace:	based on 3 yr. Life					$116,667	1
Catalyst dispose:	based on 240 ft^3 catalyst, $15/$ft^3$, 3 yr. Life					$1,200	1
Total DAC:						$168,640	
Indirect Annual Costs (IAC):							
Overhead:	60% of O&M					$0	2
Administrative:				0.02 TCI		$13,445	2
Insurance:				0.01 TCI		$6,723	2
Property tax:				0.01 TCI		$6,723	2
Total IAC:						$26,890	
Total Annual Cost (DAC + IAC):						$195,530	
Capital Recovery (CR):							
Capital recovery factor (CRF):		interest rate (%):	10				
		period (years):	15	0.1315		$88,383	2
Total Annualized Costs						$283,913	

Table 8.1E-12c

SCONOx Cost and Cost/Effectiveness (per gas turbine/HRSG)

Description of Cost		Cost ($)	Notes
Direct Capital Costs			
	Capital (less cost of initial catalyst charge)	$3,900,000	3, 7
	Installation	$1,700,000	3
Indirect Capital Costs			
	Engineering	$200,000	3
	Contingency	$250,000	3
	Other	-	
Total Capital Investment		$6,050,000	
Direct Annual Costs			
	Maintenance	$250,000	3
	Ammonia	-	3
	Steam/Natural Gas	$400,000	3
	Pressure Drop	$226,000	3
	Catalyst Replacement (based on 3-yr catalyst life)	$3,033,333	7, 8
	Catalyst Disposal	$0	
Total Direct Annual Costs		$3,909,333	
Indirect Annual Costs			
	Overhead	-	3
	Administrative, Tax & Insurance	$225,000	3
Total Indirect Annual Costs		$225,000	
TOTAL ANNUAL COST		$4,134,333	
Capital Recovery Factor		0.1315	2
Capital Recovery		$795,416	
TOTAL ANNUALIZED COSTS		$4,929,750	

SCONOx Ammonia Cost Effectiveness (per gas turbine/HRSG)

Description of Cost		Cost ($)	Notes
SCONOx Annualized Costs		$4,929,750	
SCR Annualized Costs		$956,897	
Oxidation Cat. Annualized Costs		$283,913	
SCR/Oxidation Cat. Annualized Costs		$1,240,809	
Incremental Annualized Costs		$3,688,940	
Annual Ammonia Emissions with SCR (tons/yr)		74.02	6
Annual Ammonia Emissions with SCONOx (tons/yr)		0	
Reduction in Ammonia Emissions (tons/yr)		74.02	
SCONOx COST EFFECTIVENESS ($/ton removed)		$49,836	

Table 8.1E-12d

Notes: SCONOx Ammonia Cost Effectiveness Analysis

Note No.	Source
1	Based on information from Duke/Fluor Daniel.
2	From EPA/OAQPS Control Cost Manual. EPA-450/3-90-006. January 1990.
3	From April 12, 2000 letter from ABB Alstom Power to Matt Haber EPA Region IX (SCONOx capital cost of $13,000,000).
4	Based on anhydrous ammonia cost of $450/ton.
5	Based on current average price of power in the project area.
6	Based on G.E. 7FA Gas Turbine/HRSG operating at 100% load, 43 deg. F ambient, duct burner on, ammonia slip of 5 ppm @ 15% O2, operating 24 hours per day, 365 days per year.
7	Based on information from May 8, 2000 "Testimony of J. Phyllis Fox, Ph.D. on Behalf of the California Unions for Reliable Energy on Air Quality Impacts of the Elk Hills Power Project", cost of replacement catalyst for SCONOx is 70% of initial capital investment.
8	Based on information from May 5, 2000 letter from ABB Alstom Power to Bibb and Associates indicating that SCONOx catalyst life is guaranteed for a 3-year period.

APPENDIX 8.1F

Evaluation of Best Available Control Technology

Emission Reduction Credits Needed and Owned by Applicant					
		Pounds of Offsets Req'd/ERCs per Quarter			
Pollutant		1st Qtr	2nd Qtr	3rd Qtr	4th Qtr
NOx[1]	Project Emissions	133,760	133,760	133,760	133,760
	ERCs Owned[3]	460,317	499,056	553,045	470,387
VOC[1]	Project Emissions	39,351	39,351	39,351	39,351
	ERCs Owned[3]	185,036	177,112	183,988	171,407
SO_2	ERCs Owned[4]	250,160	250,509	250,857	250,885
PM_{10}[2]	Project Emissions	97,571	97,571	97,571	97,571
	ERCs Owned[3]	53,830	77,528	21,184	132,506

Notes:
1. ERCs for NOx and VOC that occurred from April through November (2nd through 4th quarters) may be used to offset increases in NOx and VOC during any period of the year (Rule 2201.4.13.8).
2. ERCs for PM that occurred from October through March (1st and 4th quarters) may be used to offset increases in PM during any period of the year (Rule 2201.4.13.7).
3. Excluding ERCs that are otherwise committed.
4. The APCO may approve the use of PM_{10} precursors as PM_{10} offsets (Rule 2201.4.13.3.2).

APPENDIX 8.1G

Offset Listing

APPENDIX 8.1G

CUMULATIVE IMPACTS ANALYSIS

Potential cumulative air quality impacts that might be expected to occur as a result of the proposed Project and other reasonably foreseeable projects are both regional and localized in nature. These cumulative impacts were evaluated as follows.

Cumulative impacts from the Project could result from emissions of carbon monoxide, oxides of nitrogen, sulfur oxides, and directly emitted PM_{10}. To ensure that other projects that might have significant cumulative impacts in conjunction with the Project were identified, a search area with a radius of 6 miles was used for the cumulative impacts analysis.

Within this search area, three categories of projects with combustion sources were used as criteria for identification:

- Projects that are existing and have been in operation since at least 1999.
- Projects for which air pollution permits to construct have been issued and that began operation after 1999.
- Projects for which air pollution permits to construct have not been issued, but that are reasonably foreseeable.

Projects that are existing and have been in operation since at least 1999 are reflected in the ambient air quality data that have been used to represent background concentrations; consequently, no further analysis of the emissions from this category of facilities was performed. The cumulative impacts analysis added the modeled impacts of selected facilities to the maximum measured background air quality levels, thus ensuring that these existing projects were taken into account.

Projects for which air pollution permits to construct have been issued but that were not operational by 1999 were identified through a request of permit records from the SJVUAPCD. The search was requested at two levels. Projects that had a permit to construct issued after January 1, 1998, were included in the cumulative air quality impacts analysis. The January 1, 1998 date was selected based on the typical length of time a permit to construct is valid and typical project construction times, to ensure that projects that are not reflected in the 1999 ambient air quality data are included in the analysis. Projects for which the emissions change was smaller than 5 tons per year were assumed to be *de minimis*, and were not included in the dispersion modeling analysis. A list of projects within the area for which air pollution permits to construct have not yet been issued, but that are reasonably foreseeable, was also requested from the District staff.

As discussed in Section 8.1.7, no sources were identified by the District staff as meeting these criteria. Therefore, no further analysis is necessary to determine that the proposed project will not cause a cumulative impact.

sierra
research

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August 2, 2001

Dave Warner
Permit Services Manager
San Joaquin Valley Air Pollution Control District
1009 E. Gettysburg Avenue
Fresno, CA 95356-9321

Re: Cumulative Impacts Analysis
Central Valley Energy Center

Dear Mr. Warner:

Central Valley Energy Center, LLC, plans to file an Application for Certification with the California Energy Commission (CEC) for a combined-cycle gas turbine power plant near the city of San Joaquin in Fresno County. The UTM coordinates of the site are 4053.994 km northing, 752.404 km easting (NAD 83, Zone 10). As part of the project review, the CEC requires us to prepare an analysis of the project's cumulative impacts. This is defined by the CEC as "a cumulative air quality modeling impacts analysis of the project's typical operating mode in combination with other stationary source emissions sources within a six-mile radius *which have received construction permits but are not yet operating, or are in the permitting process*." [emphasis added] The CEC staff considers facilities having emissions increases of less than five tons per year to be *de minimis*, so these small increases may be excluded.

We would like to get from the District a list of projects that meet these criteria, along with sufficient emissions information and stack parameters so that we can include these sources in our air quality modeling. Please contact our accounting office at the phone number above when the information is ready, and we will provide you with a credit card number to expedite our receipt of the information.

Thank you very much for your assistance. If you have any questions regarding the information we are requesting, feel free to call.

Sincerely,

Nancy Matthews

Nancy Matthews

cc: Frank Middleton, Calpine
Tom Lagerquist, Peregrine Environmental

San Joaquin Valley
Air Pollution Control District

cc
Cal

Fax Transmittal

1990 E. Gettysburg Avenue
Fresno, California 93726-0244
Phone (559) 230-6000
Fax (559) 230-6061

Date: 8/8/01

To: Nancy Matthews   Fax Number: (916) 444-8373

From: Cheryl Lawler   Number of pages (including cover sheet): 2

Description:

- [x] Per Your Request
- [ ] Per Our Conversation
- [ ] Take Appropriate Action
- [ ] Please Answer
- [ ] For Your Information
- [ ] For Your Approval
- [ ] Review & Comment
- [ ] Review & Return
- [ ] Original transmittal will follow via mail

Remarks / Response: Nancy: There are <u>no</u> facilities within a six-mile radius of the Central Valley Energy Center site which have received Authorities to Construct but are not yet operating.